

COMMITTEE HEARING  
BEFORE THE  
CALIFORNIA ENERGY RESOURCES CONSERVATION  
AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Draft Natural Gas	)	00-CEO-VOL-1
Infrastructures Issues Report	)	
	)	
-----	)	

CALIFORNIA ENERGY COMMISSION  
1516 NINTH STREET  
HEARING ROOM A  
SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 5, 2001

10:25 A.M.

Recorded by:  
California Energy Commission  
Contract No. 150-99-001

PETERS SHORTHAND REPORTING CORPORATION (916) 362-2345

COMMITTEE MEMBERS PRESENT

Michal Moore, Presiding Member

James Boyd, representing Mary Nichols, Resource  
Secretary

STAFF PRESENT

Melissa Ann Jones

Scott Tomashefsky

Bill Wood

Kent Smith

Sy Goldstone

ALSO PRESENT

Daniel P. Kramer  
California Independent Petroleum Association

Les Buchner  
Mark Meldgin  
Brian Cherry  
Pacific Gas and Electric Company

Eric Eisenman  
PG&E National Energy Group

Douglas K. Kerner, Attorney  
Ellison, Schneider & Harris, LLP

Latimer P. Lorenz  
The Gas Company, a Sempra Energy company

Michael Murray  
Steve Rahon  
Mark Ward  
Sempra Energy

Michael Monagan  
Brad A. Barnds  
Calpine Corporation

ALSO PRESENT

Ron Oechsler  
Navigant Consulting

Tom Fillmore  
Southern California Edison Company

Mark Wolfe  
California Unions for Reliable Energy

Karen Lindh  
Lindh & Associates for California Manufacturers  
and Technology Association

Michael B. Day, Attorney  
Goodin, Macbride, Squeri, Ritchie & Day, LLP

Norman Pedersen  
Jones, Day, Reavis and Pogue

Dail Miller  
Environmental Science Assoc.

Tom Horst  
CH2M HILL

Jim Rudolph  
Karl Meyer  
Northern California Power Agency

Dave Arthur  
City of Redding

Marshall Clark  
DGS Natural Gas Service

Yong Cai  
Barry Brunelle  
Iraj Deilami  
W. Shannon Black  
Carney Ouye  
Sacramento Municipal Utility District

Rachel King  
El Paso Corporation

Richard A. Meyers  
California Public Utilities Commission

ALSO PRESENT

Edward O'Neill  
Davis Wright Tremaine

Edward Randolph  
ASM. Canciamilla

J. P. Batmale  
RealEnergy

PETERS SHORTHAND REPORTING CORPORATION (916) 362-2345

## I N D E X

	Page
Proceedings	1
Opening Remarks	1
Presiding Member Moore	1
Mr. Boyd	4
Presentations	6
CEC Staff Report	6
M. Jones	6
S. Tomashefsky	8
B. Wood	15
California Public Utilities Commission	33
R. Meyers	33
California Independent Petroleum Association	36
D. Kramer	36
Southern California Gas Company; San Diego Gas and Electric; Sempra Energy	56
L. Lorenz	56
M. Murray	
Afternoon Session	78
Presentations - continued	
Pacific Gas and Electric Company	78
L. Buchner	78
Calpine Corporation	98
B. Barnds	98

## I N D E X

	Page
Presentations - continued	
Wild Goose Storage Facility	114
M. Day	114
California Generation Coalition	129
N. Pedersen	129
PG&E National Energy Group	
PG&E Gas Transmission Northwest	
North Baja Pipeline Projects	142
E. Eisenman	142
Duke Energy North America	
Duke Energy Trading and Marketing	151
D. Kerner	151
Closing Remarks	154
Adjournment	156
Certificate of Transcriber	157

## 1 P R O C E E D I N G S

2 10:25 a.m.

3 PRESIDING MEMBER MOORE: Good morning.

4 I'm Michal Moore; I'm a Commissioner here with the  
5 California Energy Commission. I also preside over  
6 the Electricity and Natural Gas Committee. And I  
7 want to, at the very start here, apologize for  
8 what has turned out to be an awkward delay because  
9 of a technological glitch. We don't have all of  
10 our recording equipment in, and as you'll hear, I  
11 would very much like to make sure that we have a  
12 public record on this.

13 So we're going to do two things today.  
14 We're going to start by tape recording the  
15 comments that come in, and speak as loudly and  
16 clearly as you can into the microphone so we get  
17 the advantage of the testimony that you're going  
18 to offer us.

19 And second, we will have the hearing  
20 videotaped for transcription later on. So I hope  
21 to overcome the difficulties that we've had and  
22 make it up in the work.

23 We're, let me get a couple of remarks on  
24 the record here. Normally I would be joined at  
25 the dais by my colleague, Art Rosenfeld, who is

1 engaged in another hearing and other matters for  
2 the Commission right now.

3 As many of you know we all have multiple  
4 hats that we're wearing trying to make sure that  
5 power plants get sited in a timely manner and the  
6 other business of the Commission gets taken up in  
7 the sequence that it should.

8 I am joined on the dais by my aide,  
9 Melissa Jones, who is here on my right. And Jim  
10 Boyd, who is representing the Secretary of the  
11 Resources Agency, and who will be with me here  
12 during the hearing today.

13 I want to point out in the form 637 for  
14 FERC, the integrated increase in integration of  
15 gas and electric markets is reflected in many of  
16 the mergers that we see between power generators  
17 and pipeline companies, as well as the number of  
18 marketers that we (inaudible) and electricity.

19 Some of the marketers are operating  
20 their own generating plants, as you well know, for  
21 some customers the energy markets that emerge will  
22 be a new market where the customer can purchase  
23 whatever energy sources -- at the time.

24 As we've seen in all our siting cases,  
25 the preference is for natural gas firing, not

1       seeing anything else come before us. And it  
2       presages a demand increase in the future that is  
3       not trivial, and we're going to have to think  
4       about, as a state, long term, in order to make  
5       intelligent decisions, not only to regulate the  
6       market, but to assist the market in its expansion.

7               In these hearings what I am interested  
8       in, and I think we tried to make clear in the  
9       notice that went out, is that we're looking to the  
10      medium- and long-term. There are a number of  
11      hearings that have been going on at the FERC and  
12      at the PUC that I'm not interested in repeating.

13             I know we have access to the testimony  
14      there; we certainly have access to a lot of the  
15      other documents that have been produced, as well  
16      as the hearings that took place over in the  
17      Legislature here recently.

18             I'm interested in insuring that in  
19      actions for the long term, not only in the  
20      physical conditions that will prevail through the  
21      industry, but also in terms of some of the  
22      regulatory changes that may be made.

23             In a conversation I had with a couple of  
24      the FERC Commissioners not too long ago, we're now  
25      saying what happened. Obviously a lot of us could

1 speculate on the range of things that happened. I  
2 pointed out that in my opinion what we had was not  
3 so much market failure as it was regulatory  
4 failure. In other words, you're looking at one of  
5 the problems right now.

6 I want to avoid that in the future. I  
7 want to try and find ways to overcome some of the  
8 regulatory hurdles. I need your advice and  
9 counsel to start to be able to do that. And I  
10 welcome your comments on how to make the  
11 regulatory system, as well as the physical  
12 delivery system, more efficient and more  
13 predictable over time.

14 With that, let me turn to Mr. Boyd and  
15 ask if he would like to offer a comment on behalf  
16 of the Secretary. And then I'm hopeful that we  
17 can get on with the agenda.

18 MR. BOYD: Thank you, Commissioner  
19 Moore. It's a pleasure to be here today.  
20 Appreciate the opportunity to join in with you on  
21 this hearing. I think many people know earlier  
22 this year the Governor asked the Secretary to take  
23 a look at natural gas, and she has formed a  
24 working group of which the Energy Commission and  
25 all other state agencies who have any dealings

1 with the gas are -- members.

2 And we meet on a regular basis in  
3 reviewing the natural gas. A lot of what I've  
4 seen in this draft staff report reflects many of  
5 the discussions we've had within that group, and  
6 some of the information that's been passed on to  
7 the Governor's Office.

8 I hope to hear and learn even more today  
9 and look forward to additional input on this  
10 subject, as we all grapple to understand the  
11 natural gas questions and plan the immediate term  
12 and long-terms, as you mentioned, for California's  
13 benefit. So I look forward to learning a lot  
14 today. Thanks.

15 PRESIDING MEMBER MOORE: Thank you.  
16 With that, we had invited Assemblyman John  
17 Campbell to be here. Is the Assemblyman here to  
18 address us? Okay, he may, in fact, show up and  
19 we'll make time for him when he does.

20 I'm going to ask Melissa Jones to go  
21 over the report, which I assume every one of you  
22 has had -- it's buff colored, peach colored cover,  
23 and the issues -- on behalf of the staff -- I did  
24 look at it and I had some input into it before it  
25 went out. And which we are hoping to use as a

1 framework for many of our discussions today.

2 Melissa, if you'd like to outline the  
3 report and then we'll go into (inaudible).

4 MS. JONES: I am Melissa Jones and I'm  
5 with the Executive Office, with the Executive  
6 Office here at the Energy Commission. And I  
7 served as the team lead for the preparation of the  
8 analysis, and was the principal author of the  
9 report.

10 At this time I'd like to enter the  
11 report, the staff report, Natural Gas  
12 Infrastructure Issues, publication number 200-01-  
13 001, into the record.

14 The report was prepared as part of the  
15 Energy Commission's ongoing mandate to assess  
16 trends in supply and demand for all parts of  
17 energy, including natural gas, as outlined in the  
18 Public Resources Code sections 25216, 25309, 25310  
19 and 25320.

20 The Energy Commission is also mandated  
21 to carry out studies relating to potential  
22 shortages of electricity, natural gas and other  
23 sources of energy, and to make recommendations to  
24 the Governor and the Legislature to avert supply  
25 emergencies or fuel shortages under the Public

1       Resources Code section 25704.

2               In addition, recently passed legislation  
3       SB6X, which sets up the power authority, mandates  
4       that the Public Utilities Commission, in  
5       consultation with the Energy Commission, presents  
6       a report that looks at the present plan and  
7       requires future capacity of the state's natural  
8       gas transportation and storage system to provide  
9       adequate seasonal supplies to customers, including  
10      electric generating plants.

11              In this report the staff assessed four  
12      essential elements of the infrastructure for  
13      natural gas necessary to assure adequate supplies  
14      to California's consumers.

15              These included drilling rigs to produce  
16      natural gas from underground reservoirs; the  
17      interstate pipelines to deliver this remote gas  
18      from production basins outside of California to  
19      the California border; the intrastate pipeline to  
20      deliver the gas supplies from the border to end-  
21      use consumers; and finally, the storage facilities  
22      that are used to supplement gas flowing through  
23      the pipelines to meet peak demand.

24              Staff also addressed the high electric  
25      generation demand that we anticipate, which under

1 the historic drought conditions that are currently  
2 being experienced in the west that is expected to  
3 challenge the natural gas system in the near term.

4 Staff also believes that a major  
5 contributor to the high natural gas prices which  
6 California has been experiencing is increased  
7 demand for natural gas by electric generators, and  
8 the infrastructure constraints that that demand  
9 has posed to the system.

10 With that, I'm going to go ahead --  
11 before I do that I would like to first acknowledge  
12 Gary (inaudible) that put together this effort.  
13 I'd like to acknowledge the staff people who are  
14 involved, Bob Logan, Bill Wood, Todd Peterson,  
15 Scott Tomashefsky, Leon Braithwaite, (inaudible),  
16 David (inaudible) and Angela (inaudible). They  
17 all played an instrumental part in getting this  
18 report done and conducting the analysis in the  
19 short timeframe that we had.

20 And so with these introductory remarks  
21 I'd like to turn on the dais to Scott Tomashefsky  
22 who will look at medium-term infrastructure needs.

23 MR. TOMASHEFSKY: Thanks, Melissa. I'm  
24 going to move over to the keyboard so I can run  
25 the slides.

1                   PRESIDING MEMBER MOORE: Make sure that  
2                   microphone is on, because that one doesn't sound  
3                   like it is.

4                   MR. TOMASHEFSKY: Good morning,  
5                   everyone. My brief presentation is probably the  
6                   only restatements of things you've seen in  
7                   Washington and the PUC and other forums. Just  
8                   another on some of the infrastructure development  
9                   that is going on in California.

10                  Clearly the problem here that we've been  
11                  dealing with is the infrastructure to support the  
12                  growing needs of power generation. That seems to  
13                  be the area that really put us over the hump in  
14                  2000. Things were rolling along in the gas market  
15                  relatively well through the early part of 2000,  
16                  and (inaudible) not exaggerating. (inaudible)  
17                  prices are somewhat unexplainable in certain  
18                  circumstances.

19                  PRESIDING MEMBER MOORE: Scott, you're  
20                  going to have to speak closer to the microphone.  
21                  I'm sorry.

22                  MR. TOMASHEFSKY: No problem. From the  
23                  power generation perspective we clearly have one  
24                  of the more diverse arrays of generating needs,  
25                  generating types in California. Our in-state

1 capacity is about 53 gigawatts generation. A lot  
2 growth expected behind that.

3 And as you can see here with this slide,  
4 generation does not discriminate in terms of where  
5 it's located throughout the state. So very  
6 important in terms of how natural gas -- many of  
7 those facilities.

8 Again, another perspective, is that a  
9 quarter of our (inaudible) generator capacity  
10 sources is very important in terms of how  
11 intrastate pipelines are actually (inaudible) in  
12 California and how power generation can impact the  
13 amount of available gas supply in the state.

14 I have one more. Depending on hydro  
15 conditions, which this year is probably -- that 40  
16 percent probably closer, generation could account  
17 for as much as 40 percent of gas consumed in  
18 California. As I said earlier, the power  
19 generation (inaudible) especially down in Arizona.  
20 It's very important.

21 In terms of what we've done here, our  
22 staff has been working in the last three years  
23 now, reviewing and approving projects, working  
24 with applicants to get the projects in working  
25 order, to get facilities licensed, and

1 construction, and hopefully generation process.

2 There are, of course, (inaudible) should  
3 be on line within a month, but in terms of what  
4 we've approved, we've approved approximately  
5 11,000 megawatts in new generation, with another  
6 15,000 either under review or publicly announced,  
7 and probably another 10,000 in the formulating  
8 stage. So, we're certainly not short of activity  
9 here in terms of licensing operations.

10 The main thing to point out here is  
11 there that this is all gas-fired. What does this  
12 mean for gas? It's all gas-fired with the  
13 exception of the small renewables, not part of  
14 that number that I showed previously.

15 Clearly the infrastructure needs to be  
16 enhanced, and again, generation growth throughout  
17 the west will impact that. The presentations will  
18 really get into what's generally going on  
19 infrastructure-wise.

20 This is taken off of our webpage. This  
21 represents nonCalifornia-related generation in the  
22 west, which is mostly, if not all, gas-fired.  
23 Another 50,000 megawatts on top of generation  
24 that's ready and could be out there, which needs a  
25 home in terms of pipeline capacity to support it.

1                   This gives you an indication, the next  
2           couple slides will show you, from a Kern River  
3           perspective, for example, you can see that there's  
4           clusters of generation in Kern County in this  
5           part. The other part is really in the Las Vegas  
6           area. And for our purposes, if we don't pay  
7           attention to what's going on in the Las Vegas area  
8           and upstream of even Las Vegas, we can potentially  
9           come to the conclusion in terms of how much  
10          generation expansion, gas expansion, is actually  
11          out there. How much expansion is really going to  
12          be used in the California marketplace.

13                   In the Kern situation some of that  
14          additional capacity that they're looking to build  
15          doesn't serve California generation markets.

16                   This tells the story for the Pacific  
17          Northwest. It's not much different in terms of  
18          concept, just really the main issue here is that  
19          there is lots of upstream generation being  
20          proposed, and therefore there are significant  
21          impacts on gas available to California.

22                   This slide you've probably seen  
23          variations of over the last six weeks or so, but  
24          this just gives you a synopsis of the delivery  
25          capacity to California on the interstate pipeline.

1       You can quibble with the 7000, depending on how  
2       you calculate the numbers, but this, in  
3       combination with the next slide on receipt  
4       capacity, there's a clear message that there is an  
5       imbalance in the delivering capacity, received  
6       capacity at the California border, which is  
7       arguably one of the reasons for the price run-up,  
8       especially in southern California. And there are  
9       others who will talk to that, as well.

10               This is another one as far as storage.  
11       One addition there is Lodi Gas, which is expected  
12       to be operational by, I'm assuming, around the end  
13       of this year.

14               So the good news is that the industry is  
15       responding. The gas industry seems to work pretty  
16       well together, so that's good news. It's not as  
17       cut-throat as the electricity folks --

18               (Laughter.)

19               MR. TOMASHEFSKY: This just gives you an  
20       idea of some of the various proposals that are on  
21       the books. I'm not going to go through each one  
22       of these, so we can get on with our presentations.  
23       But, what it does show you, the interstate  
24       companies are not sitting by the wayside, not  
25       proposing to do things. There's a lot of binding

1 agreements that are supporting some of these  
2 expansion proposals, a lot of good (inaudible) for  
3 longer term expansions.

4 The timing for some of the on-line dates  
5 are different depending on whether (inaudible),  
6 but it's all in of having capacity and much of it  
7 will serve California.

8 The same statement really holds true for  
9 in-state. The utilities are stepping up to the  
10 plate in terms of coming up with proposals, really  
11 assuming risk that they ordinarily would not  
12 assume in terms of nonrecovery of various projects  
13 subject to rate recovery at some point.

14 And the same holds true for storage  
15 facilities; SoCal's had trouble with very dynamic  
16 proposals to deal with, short-term problems with  
17 having additional capacity available, and storage  
18 is being expanded and/or developed. So there is a  
19 lot of activity that is occurring on all areas of  
20 the infrastructure (inaudible) are positive.

21 The general observation I will turn over  
22 to Bill is that we clearly are in a tight  
23 situation. I don't think anyone argues with that.  
24 We've done pretty well so far, and we've actually  
25 had very warm days, so we've done well. There is

1       some capacity relief that's going to be on line by  
2       this winter, and the pipeline companies are  
3       stepping up.

4                   So, with that, I'll turn the podium to  
5       Bill.

6                   MR. WOOD: Good morning, Commissioner  
7       and audience. Delighted to be here, I guess.

8                   (Laughter.)

9                   MR. WOOD: I can think of better things  
10       to do, I'd rather be in my backyard working in my  
11       garden, but here we are, working with problems  
12       associated with natural gas.

13                   Today I'd like to speak principally  
14       toward the thing that I had some concern during  
15       the last couple years. That would have to be with  
16       utility pipeline capacity and utilization and  
17       storage for noncore requirements.

18                   Specifically today I'm going to be  
19       discussing three areas: Are new utility pipeline  
20       planning guidelines needed to insure that we have,  
21       and will be able to meet any future demand that  
22       may come along.

23                   If we are to increase our capacity, then  
24       who's going to pay for this. And then what about  
25       storage in regards to a lot more customers.

1 I'm going to go back in history for just  
2 a shade, for just a moment here. Back about ten  
3 years ago when all the new pipeline capacity came  
4 in the question was did California have too much  
5 pipeline capacity.

6 And the thought was yes, we probably  
7 did. We had overbuild in the particular capacity  
8 that we had in line that came in in the 1992, '93  
9 timeframe was going to be sufficient to last us  
10 for a long time to come.

11 During that period of time we had the  
12 Kern River and Mojave expansions and pipeline  
13 capacity that came into the state. And to meet  
14 some of that requirement, then, we had El Paso and  
15 Transwestern build capacity to deliver it to  
16 Mojave.

17 PG&E built receiving capacity at Daggett  
18 to receive gas from both of those, both Kern River  
19 and Mojave. SoCalGas built its capacity at  
20 Wheeler Ridge to receive gas also from Mojave and  
21 Kern River, as well as receiving gas from PG&E.

22 And then a year later, after the  
23 completion of the Kern River/Mojave project, PG&E,  
24 which was then PGT, but we now have new acronyms,  
25 PG&E GTN was built with the capacity being

1 delivered to California and PG&E stepped up, and  
2 after a little torture, I guess, they were  
3 actually allowed to build capacity to receive gas  
4 from the GTN expansion.

5 Things have changed since the  
6 development of those new pipelines. In this area  
7 it was generally agreed and thought that we had  
8 overbuilt and would not need any capacity for  
9 awhile.

10 During the same time natural gas prices  
11 continued to be low and these all combined to lead  
12 to noncore customers converting to natural gas.  
13 Gas was cheap and there was plenty of pipeline  
14 capacity available, so why not convert over for  
15 economic purposes. Gas was easier to work with  
16 than working with the alternative fuel such as  
17 residual or distillate fuels.

18 And then, of course, there were quality  
19 regulations came into play, which further required  
20 noncore customers to shift away from utilizing  
21 fuel oils as their alternative fuel, and rely  
22 specifically on natural gas.

23 But gas demand has grown and we see that  
24 it's going to continue to grow. Here's a couple  
25 of snapshot years of two of them historic, two of

1       them forecasted. Our gas demands since 1995 has  
2       gradually grown. It peaked, if you would, in the  
3       year 2000, but it evens to a level of about 6700  
4       MMcfd. That includes utility and non-utility  
5       consumption.

6               We had forecast over this year in the  
7       area of 6.4 billion cubic feet per day. So, we  
8       almost hit it, but because of the drought  
9       conditions we overshot.

10              And as you see, we see gas demand kind  
11      of falling off, or remaining flat for the next  
12      five years, after which demand will grow reaching  
13      a level of approaching 7.8 billion cubic feet per  
14      day.

15              The question may arise, well, what's  
16      going on between 2000 and 2005. I see 2000 as  
17      being kind of a preview of the gas demand that  
18      we're going to see later on in the years, and  
19      later on in this decade. These levels were  
20      spurred principally because of the low hydro  
21      conditions that are being experienced in the west  
22      coast.

23              With regard to the level or the quality  
24      demand between -- total demand between now and  
25      2005, I've laid it on two different things that

1       are going on. First, the new electric generation  
2       that's being built to meet the electric  
3       requirement that we were short of here in the last  
4       few years. And secondly, the new efficient  
5       electric generators will be replacing the older  
6       machines that weren't that efficient.

7               And as a result, as this comes into  
8       play, then we will see actually a leveling off of  
9       gas demand. Some thought that actually with all  
10      this new generation gas demand would actually  
11      increase, but in reality, until those old machines  
12      are replaced, gas demand will continue to decline.

13             But after 2005 the growth in demand in  
14      gas for electric generation overshadows any new  
15      replacements that have occurred, and actually gas  
16      demand then grows pretty near lockstep with what  
17      is occurring on the electric generation side, or  
18      the demand for electricity.

19             So, as we see, gas is growing, and  
20      overall we can see, as we indicated in the slide  
21      that Scott had earlier, our total receiving  
22      capacity is in the area of 7.7 billion cubic feet  
23      per day. That's 6.7 from out-of-state pipeline  
24      capacity, as well as about another billion cubic  
25      feet of California production.

1                   And those two supply sources being both  
2                   for utilities and nonutility requirements. When  
3                   you compare those with our forecasted demand, it  
4                   doesn't show very much slack capacity available to  
5                   meet our requirements.

6                   As Scott indicated, steps are being  
7                   taken to meet the increased gas demand. Utilities  
8                   are taking steps to increase their receiving  
9                   capacity, both in SoCalGas and PG&E, and actually  
10                  San Diego just -- I guess SoCalGas just finished  
11                  adding on expansion in line 6900 into the San  
12                  Diego system, which occurred, what, three or four  
13                  weeks earlier than -- or a month or so earlier  
14                  than was anticipated to help relieve the demand,  
15                  the problems that are there, the supply problems  
16                  that are there.

17                  In addition, many of the interstate  
18                  pipelines are moving quickly to meet the need for  
19                  California's future demand. It almost reminds me  
20                  of the late 1980s and early 1990s when there was a  
21                  big rush to building capacity in California. And  
22                  during that period of time we had many many  
23                  pipelines, proposed pipelines to serve California.  
24                  And out of those maybe three survived, and the  
25                  rest, you can see what happens then, with the

1 numbers that have occurred, being proposed at this  
2 time.

3 Okay, talked about slack capacity. What  
4 is the purpose for adding slack capacity? In  
5 essence, it provides flexibility for those who are  
6 operating the gas system. And particularly we're  
7 talking here with regards to the California  
8 utilities, and principally towards what we call  
9 backbone, or the big-inch pipes and for bringing  
10 the gas to the California border to the -- into  
11 the load centers.

12 Natural gas provides a gas transport  
13 besides meeting the daily requirements, it also  
14 meets the storage injection requirements. Slack  
15 capacity allows for competition which helps to  
16 keep natural gas prices low.

17 I think the excess capacity we had in  
18 the mid to late '90s was one of the reasons why we  
19 enjoyed low prices in California.

20 It also insures gas supply during peak  
21 demand periods when coupled with storage  
22 availability.

23 But here's something new that we might  
24 want to consider. Should we have slack capacity  
25 to insure not only the peak demand during those

1 peak demand periods, but also to continue to  
2 provide natural gas at competitive prices.

3 That means that instead of going right  
4 up to the very top of our requirements, should we  
5 have capacity to meet even above that, so that  
6 competition can continue.

7 Let me expand on that just a shade here.  
8 The current planning criteria looks for utilities  
9 to design around a very cold day. And when  
10 coupled with the pipeline capacity and storage  
11 withdrawal to insure that gas supply is available  
12 to meet core needs on that peak day.

13 And generally that peak day is  
14 considered to be a peak winter day demand that is  
15 associated with, normally I think it's peak days  
16 are demand that occur -- or temperature occurred  
17 in the 1930s, early 1930s.

18 This level of demand may occur for a  
19 couple hours, or it may continue for a day, or it  
20 may even continue for several days. And normally  
21 storage and whatever is available to help take  
22 care of those requirements.

23 But, should pipeline planning  
24 requirements be changed from using the average  
25 peak day requirement. Gas demand will be growing

1 fast during the next ten years.

2 Gas costs for 2000 more than doubled the  
3 state's previous, roughly \$7 billion that we  
4 normally experience. And California gas consumers  
5 cannot afford to have another set of years like we  
6 have now, that we've been experiencing.

7 Without changing the infrastructure  
8 planning, there is nothing to prevent excessive  
9 high prices from occurring again, other than not  
10 having those adverse peak periods occur.

11 I kind of put together my thoughts with  
12 regards to a few of the planning options for slack  
13 capacity. California has two peak periods, winter  
14 and summer. Is designing for one enough?

15 I was looking at this for this year, in  
16 January our demand was about 6 billion cu/ft per  
17 day -- or I'm sorry, in January of 2000. In July  
18 the utility demand was 8.2 cu/ft per day. And in  
19 December the combined demand was about 8.5 billion  
20 cu/ft per day.

21 So here we have both summer and the  
22 winter we had for this past year that were very  
23 close to each other in the area of peak billion  
24 cubic feet per day.

25 What about designing to meet the dry

1 year conditions, and then, of course, the question  
2 is what is a dry year. I think back to the  
3 1977/78 timeframe when the last eight dry years --  
4 northern California.

5 During that time PG&E's big units that  
6 we're now running heavily ran full time. They had  
7 capacity factors in the area of 90 or 95 percent.  
8 That was during a period when we didn't have the  
9 new pipeline capacity we have now, and they were  
10 drawing between 100- and 125-million barrels of  
11 oil a year in those facilities.

12 So, it may be that as a kickoff point  
13 for discussion if one were to use a dry year  
14 condition maybe something in the area of 20- to  
15 25-year drought condition would be something that  
16 would be worth considering as a place to start in  
17 the analysis.

18 Who is to be included in the analysis?  
19 I mean who's going to be included to, when I say  
20 analysis I mean who should be included, what kind  
21 of capacity should we be designing for. Should it  
22 just be for core, or should you also include the  
23 noncore demand. And if so, who can the -- can the  
24 noncore be divided or included.

25 You know, people look for, there are the

1        highly essential services, power generation has  
2        been highlights; someone says refinery; someone  
3        says pipelines that move fuel from one place to  
4        another. Others have postulated hospitals and  
5        there are many other kinds of interests that may  
6        be considered here.

7                    So that's another area that needs to be  
8        evaluated with regards to who should be included  
9        in the analysis.

10                   Now, I had postulated, several slides  
11        back, something with regards to let's take a  
12        different approach and not our analysis. Let's  
13        look to see if we can provide slack capacity to  
14        insure supply on those adverse day, as well as  
15        provide competitive prices. That would require 15  
16        to 20 percent more capacity than just to meet the  
17        peak demand.

18                   And this would, of course, be something,  
19        if we're talking of this, this would be something  
20        that would occur if we're using a dry year  
21        conditions, something that would occur every about  
22        every 20 or 25 years.

23                   And understand that on a cold year  
24        situation the demand only occurs for a few hours  
25        to a few days. Well, when we're into a hydro

1 condition, that hydro condition can last for a  
2 year or two or three. So, it's much more severe  
3 when we hit a dry hydro.

4 So investing several hundred million  
5 dollars in instate infrastructure in advance could  
6 save that same quantity on a daily basis just in  
7 the commodity components.

8 I think our report kind of indicates  
9 that we believe that one of the reasons that we've  
10 experienced high prices, and in some cases double  
11 what the base prices are at the California border,  
12 because of capacity constraints that are within  
13 California.

14 If those capacity constraints had been  
15 alleviated we'd be experiencing something closer  
16 to base prices for transportation. If we were to  
17 take those differentials, the basis differentials  
18 that are now occurring that are in the \$2 to \$5  
19 range, I'm sure that if we did the calculations  
20 we'd come up with more than \$200 million in costs  
21 per day that are associated with those higher  
22 prices we're now experiencing.

23 Having slack capacity for the short-  
24 lived peak summer and winter demand is not that  
25 necessary. We can take care of those kinds of

1 things with storage. And they wouldn't have such  
2 a great impact on prices. And if they did, it  
3 would be very short-lived. But if the capacity  
4 was available, the price spikes would be minimal,  
5 if at all.

6 The question about always come up, who  
7 should pay. Without trying to highlight which is  
8 best or any kind of priorities here, there are  
9 several options that I've considered. You could  
10 roll in all the costs so everyone pays. This is,  
11 in essence, the process that SoCalGas is proposing  
12 for their expansion.

13 You could provide a seasonal demand  
14 change charges that are associated with operating  
15 on the system. You can convert all rates to  
16 provide that the more you use the more you pay, so  
17 for those people who have high peaking functions  
18 would potentially pay more than they would if they  
19 were more levelized, because you have to design  
20 capacity to meet that higher demand. So shouldn't  
21 maybe those people who use that higher demand have  
22 a part in sharing in those costs.

23 And then, of course, another process  
24 would be to have incremental users pay for  
25 incremental costs that are associated with adding

1 capacity to meet their requirements.

2 It may very well be that a combination  
3 of all of these would be, rather than just using  
4 one, but a combination of one or two or all of  
5 these would be an appropriate way to insure  
6 receiving, that the utility would be made whole  
7 for investing in capital to increase their  
8 capacity to deliver gas, particularly to meet that  
9 long-term requirement we're talking about.

10 Just a few minutes with regard to  
11 storage concerns. Earlier in the year, February,  
12 March timeframe, we were very very concerned as to  
13 whether we were going to get enough gas in the  
14 storage to meet the core requirement.

15 Fortunately, the weather has held off  
16 for us and both SoCal and PG&E have moved very  
17 diligently and quickly and taken advantage of  
18 their storage capacity to get gas into storage.  
19 And at this point in time both facilities are very  
20 healthy with regards to gas storage.

21 We've still got a ways to go to meet the  
22 winter requirements, but they're well on their way  
23 there.

24 However, natural gas, noncore natural  
25 gas injection is also occurring, but other than

1 price there doesn't seem to be an incentive for  
2 noncore customers to use storage. There's no  
3 reliability requirements associated with them;  
4 there's no fall-back if they have to go back into  
5 using flowing supply. And if that does occur, it  
6 has a double impact of causing potentially -- we  
7 do not have slack capacity, to cause prices to go  
8 up, not only for them, but for everybody that is  
9 purchasing gas.

10 So, what's to be done with our noncore  
11 customers. During the last six months I've made a  
12 lot of rounds talking with lots of people in  
13 various areas. And everybody is concerned about  
14 getting gas into storage to meet the noncore,  
15 particularly the electric generation requirements  
16 for this coming year.

17 We are concerned; the CPUC is concerned;  
18 gas utilities are all concerned. I talked to a  
19 number of people at the Legislature, they're  
20 concerned about it. They're actually looking at  
21 ways to legislate the requirement to have natural  
22 gas in storage for power generation.

23 And then a lot of consumer groups are  
24 also concerned because not having gas in storage  
25 to meet the electric generation requirements can

1 reflect upon their particular industries or people  
2 they represent with regards to the potential of  
3 higher prices.

4 So here's some possible paying system  
5 that I kind of put together. This is something I  
6 asked, posed the question, is there something more  
7 than prices needed to provide that incentive.

8 In our report we've mentioned rebundling  
9 the utility storage operations. That's a simple,  
10 potentially easy solution. And we threw that out  
11 for discussion, and we talked to a number of  
12 individuals since the report has been published.  
13 And we've had some very interesting discussions  
14 with regard to that particular comment. We'll  
15 leave it to them to provide those to the  
16 Commission.

17 But I kind of, while I was putting the  
18 final touches on this report last night, I kind of  
19 thought up a few others that kind of came to mind.  
20 One would be could the ISO require, through their  
21 RMR contracts, that certain or all or some of the  
22 generators be required to provide some sort of gas  
23 storage, some sort of gigawatt requirement or  
24 generation requirement. Not necessarily all of  
25 their requirement, but some sort of a load

1 requirement for each season.

2 Also, I haven't looked at DWR contracts.  
3 Could they require storage --

4 PRESIDING MEMBER MOORE: Neither has  
5 anyone else.

6 (Laughter.)

7 MR. WOOD: Yeah, that's true. Thank  
8 you, Commissioner.

9 DWR contracts, could they require  
10 storage with regards to insure that reliability,  
11 they will be able to give that energy that they're  
12 purchasing.

13 I haven't explored this, but FERC could,  
14 through some of its regulatory powers, might be  
15 able to require merchant plants to have storage,  
16 natural gas storage, rather than having  
17 alternative fuel capabilities.

18 And another one, Commissioner, I  
19 haven't, I thought about last night, and maybe  
20 this is off the wall, but with regard to our  
21 siting conditions require a level of storage  
22 before we license a power plant.

23 And of course there's this other area,  
24 encourage secondary storage --

25 (End tape 1A.)

1                   MR. WOOD:   Anyway, here's a few ideas  
2                   that I have thrown out.  I'd love to hear what  
3                   other people have to say with regards to these,  
4                   and maybe we need to have a working dialogue with  
5                   some before we move forward further.

6                   Pulling this all together I have two  
7                   particular concerns, then, that I highlighted in  
8                   the very beginning.  New intrastate receiving  
9                   capacity guidelines need to be resolved to insure  
10                  the 2000/2001 natural gas problems are limited in  
11                  the future.

12                  That those problems that we have now  
13                  will be limited in the future years to the best  
14                  that we can plan for.

15                  And, of course, I feel that there  
16                  definitely needs to be some sort of incentive to  
17                  insure the noncore customers, in particular, in  
18                  this case, the power generators, place natural gas  
19                  in storage to meet their summer and winter demand.  
20                  Particularly during those periods of time when  
21                  it's anticipated the demand is going to be very  
22                  very high.

23                  That completes my presentation.  I'm  
24                  open for any questions.

25                  PRESIDING MEMBER MOORE:  Thank you, Bill

1       and Scott. I assume you will be with us during  
2       the day here and be available to answer questions,  
3       or respond as we take testimony. I appreciate  
4       that very much.

5               Let me turn to the agenda that we've set  
6       up, and ask some of the parties to come up and  
7       address us. We've invited our sister agency, the  
8       PUC, to come and I'm not sure whether a  
9       representative of the PUC is here.

10              Please come forward and address us. I  
11       would assume that you're not Trina Horner.

12              MR. MEYERS: That's correct.

13              PRESIDING MEMBER MOORE: Welcome. And  
14       if you'd give us your name and your title. You  
15       have to stand very close to that microphone, if  
16       you're too far away it won't work.

17              MR. MEYERS: Thank you, Commissioner.  
18       My name is Richard Meyers. I work for the Energy  
19       Division at the California Public Utilities  
20       Commission.

21              And I didn't really have any prepared  
22       remarks, but I just wanted to say that the Public  
23       Utilities Commission is very interested in these  
24       natural gas infrastructure issues. We, as many  
25       parties in the room know, that we held our own

1 workshop here on April 17th at the Commission to  
2 discuss many issues that we're discussing here  
3 today.

4 We are also having investigation 0011002  
5 ongoing to examine San Diego Gas and Electric  
6 Company and SoCalGas capacity issues, as well as  
7 SDG&E curtailment rules.

8 We have an order instituting rulemaking,  
9 0103023, which will be examining the curtailment  
10 rules for SoCalGas and PG&E.

11 In investigation 9907003 the Commission  
12 has before it a proposed decision in what is  
13 called the gas industry reform proceedings.

14 And in application 0006032, the  
15 Commission, I believe, has just issued a proposed  
16 decision on what is called the residual load  
17 service tariff for SoCalGas.

18 The Commission is also expected to issue  
19 its decision shortly regarding the Montebello  
20 storage application by SoCalGas. And will be  
21 examining very shortly the SoCalGas application  
22 regarding Aliso Canyon and the La Goleta storage  
23 field.

24 I believe that PG&E announced an open  
25 season recently regarding intrastate capacity on

1       its system. And we expect that PG&E will be  
2       making some type of filing before the Commission  
3       regarding intrastate capacity additions that it  
4       specifically wants to propose.

5               Finally, the SoCalGas and SDG&E -- is  
6       now scheduled for, I believe, September 17th of  
7       this year, and we expect any remaining cost  
8       allocation or rate design issues could be  
9       addressed in that proceeding, as well.

10              So that's just what I'd like to say.

11       Thank you very much for allowing me to speak.

12              PRESIDING MEMBER MOORE: Let me ask you,  
13       did you have access to our staff report?

14              MR. MEYERS: I did receive it last week.

15              PRESIDING MEMBER MOORE: And is your  
16       Commission planning to make any comments on that?  
17       Do you intend to offer remarks --

18              MR. MEYERS: I don't know if the  
19       Commission is intending to make any written  
20       remarks.

21              PRESIDING MEMBER MOORE: And who is  
22       presiding on the OIR that you mentioned?

23              MR. MEYERS: The order instituting  
24       rulemaking on the curtailment rules?

25              PRESIDING MEMBER MOORE: Right.

1                   MR. MEYERS: I can't remember the  
2                   judge's name right now. I believe it's Tim  
3                   Campbell -- I mean Tim Sullivan.

4                   PRESIDING MEMBER MOORE: No, I meant  
5                   what Commissioner's presiding.

6                   MR. MEYERS: I don't know the  
7                   Commissioner's name.

8                   PRESIDING MEMBER MOORE: Thank you very  
9                   much.

10                  MR. MEYERS: Um-hum, thank you.

11                  PRESIDING MEMBER MOORE: Dan Kramer, are  
12                  you here?

13                  MR. KRAMER: I'm here.

14                  PRESIDING MEMBER MOORE: Independent,  
15                  good. Welcome. You can use the podium or --

16                  MR. KRAMER: Thank you very much. While  
17                  CIPA is submitting more detailed formal testimony,  
18                  I'd like to summarize the Association's comments  
19                  and take any questions that you might have about  
20                  some of the issues that I'll raise today.

21                  Just for the record, my name is Dan  
22                  Kramer. I'm the CEO of the California Independent  
23                  Petroleum Association. We represent over 400  
24                  independent oil and natural gas producers, and the  
25                  companies that provide services to those producers

1       that operate in California.

2               CIPA is pleased that the Commission has  
3       recognized the potential and benefit of  
4       encouraging in-state natural gas production and  
5       the removal of impediments to producing  
6       California's indigenous resources.

7               Specifically, CIPA supports the  
8       following items contained in the draft report:  
9       We're pleased that the report recognizes  
10      officially the locational advantage of California  
11      natural gas production, and that it supports  
12      incentivizing the production of this resource.  
13      That's a welcome policy change from the past, and  
14      we appreciate its inclusion in the final report.

15              CIPA supports the Commission's effort to  
16      identify dysfunction in current regulatory and  
17      utility policies with regard to the interstate and  
18      intrastate pipeline infrastructure, capacity  
19      constraints and natural gas delivery to end-use  
20      customers. I'll talk a little bit about that  
21      later in my remarks.

22              CIPA agrees that there should be a  
23      mechanism to monitor in-state drilling rig  
24      activity and production levels to assess whether  
25      production is keeping pace with demand. This

1 information should be shared with local, state and  
2 federal policymakers to provide an early warning  
3 system on future supply needs.

4 Our members would be pleased to  
5 cooperate in any effort to coordinate that kind of  
6 a function; and would appreciate the official  
7 stamp of approval of the California Energy  
8 Commission in that effort. We'd welcome that  
9 opportunity.

10 CIPA agrees that barriers to increased  
11 California gas production should be identified as  
12 you recommend in your report, and that the CEC and  
13 CPUC should recommend and support legislative and  
14 regulatory actions to increase in-state natural  
15 gas supplies.

16 CIPA has -- I have here several  
17 suggestions, but it's actually a laundry list of  
18 suggestions, that if implemented collectively  
19 could make a very significant contribution to in-  
20 state gas supply.

21 While the testimony, the official  
22 testimony goes on and on, what I specifically want  
23 to address today with you is how do we increase  
24 California natural gas production, addressing that  
25 specific issue.

1                   As I've said, with the proper  
2           combination of regulatory -- incentives California  
3           producers will produce more natural gas in state.  
4           I think it's also important to recognize the  
5           distinction between dry gas and associated gas  
6           production, which I didn't see in the report  
7           anywhere. But I believe should be addressed.

8                   And, of course, dry gas is that gas is  
9           produced primarily as an end-use commodity. And  
10          the associated gas production that I refer to is  
11          the gas that's produced along with oil production.  
12          Dry gas, as you know, is typically produced in  
13          northern California; and southern California  
14          typically produces most of the associated gas  
15          production.

16                   PRESIDING MEMBER MOORE: So you think  
17          that we just literally didn't address that issue  
18          and we should have had --

19                   MR. KRAMER: I think it should be  
20          specifically pointed out, because I believe still  
21          the majority of California's production is  
22          actually associated gas production, or pretty  
23          close to it. And that supply could be increased,  
24          as well. And it is used throughout the state for  
25          various processes.

1 PRESIDING MEMBER MOORE: Okay.

2 MR. KRAMER: For that reason any  
3 applicable incentives that are enacted to  
4 encourage the production of California natural gas  
5 should apply both to oil and gas wells that are  
6 producing marketable gas or gas to be used in any  
7 process.

8 I think it's important to single that  
9 out and particularly if you are making any  
10 recommendation, or the Commission's making any  
11 recommendations to the Legislature, or to other  
12 regulatory agencies, that distinction should be  
13 made.

14 I think it's no secret we've been  
15 talking about the issue for the past ten years  
16 independent producers throughout the state report  
17 experiencing delays of six months to a year before  
18 receiving utility approval to install new pipeline  
19 interconnections, and really basically to get new  
20 wells hooked up to the system.

21 Utilities essentially control that  
22 process, whether directly through explicit mandate  
23 or in a de facto fashion. And many of the  
24 suggested incentives and directives that we're  
25 about to address will talk or speak to that issue.

1                   Strong evidence suggests that simply  
2                   expanding production and reforming the regulatory  
3                   relationship between the producers and the  
4                   utilities could address a significant portion of  
5                   our long-term natural gas needs.

6                   I believe in your report you point out  
7                   that 15 percent of the state's current supply is  
8                   provided by in-state production. And some of your  
9                   own folks here recognize the historical reality of  
10                  producers potentially providing up to 25 percent  
11                  the state's in-state production. With the right  
12                  incentives we believe we could get close to that  
13                  number.

14                  I'd like to list some of the suggested  
15                  reforms that we're proposing, that we've got out  
16                  in the public arena, either in the legislative  
17                  process or in a variety of regulatory forms.

18                  We believe that the existing California  
19                  Natural Gas Policy Act should be strengthened, and  
20                  we should establish mandatory timeframes under  
21                  which a utility must respond to a producer's  
22                  request for a pipeline interconnection, and by  
23                  providing new incentives for utilities to accept  
24                  in-state gas.

25                  We should create an oversight process

1       with the PUC or CEC to enforce rules and  
2       regulations requiring the utilities to accommodate  
3       a producer's need for hook-up. I think there was  
4       a reference in the report, maybe one or two lines,  
5       to that effort. We strongly believe that.

6               We believe we should encourage new  
7       exploration activity by requiring utilities to  
8       install new metering sites or by allowing  
9       producers to do it themselves. Something that we  
10      requested for the past at least five years. We  
11      believe we can do it as well or better than the  
12      utilities, rather than require producers to  
13      construct miles of new pipeline for every new  
14      exploratory well.

15             We should allow producers or the  
16      Commission should recommend that we allow  
17      producers to expedite the installation of new  
18      pipeline interconnects and well interconnects by  
19      authorizing them to shoulder costs such as  
20      pipeline construction and labor costs if the  
21      utility's workforce is already overburdened.

22             In other words, producers have offered  
23      to pay for a lot of this new interconnection.  
24      They've offered to pay for pipeline. They've  
25      offered to pay for the labor, if they can do it

1       quicker. And I believe that offer still stands.  
2       And we have put that out here in a public forum  
3       and encourage the utilities to take advantage of  
4       that offer to get in-state gas into the  
5       marketplace to address our current supply deficit.

6               We should require the utilities to allow  
7       in-state production to flow to alternate markets  
8       in instances where the utilities are curtailing or  
9       cannot provide standard services without penalty  
10      to the producer.

11             Right now it's very difficult for  
12      producers to send their gas to alternative markets  
13      if the utilities don't give their explicit assent  
14      to do that.

15             We should require the utilities to sell  
16      off their existing gathering systems to interested  
17      producers and co-ops, and provide the producers  
18      the authority to maintain and service the  
19      gathering systems as mandated by AB-1890 on the  
20      gas report.

21             Your report specifically touches on that  
22      issue. I believe that there's a reference in  
23      there to spinning off the natural gas gathering  
24      system in northern California. But the explicit  
25      reference in the report seems to indicate that the

1       best and highest use would be to spin that off  
2       with a single entity, where producers would like  
3       to have the opportunity to purchase all or  
4       portions of their gas gathering systems. And  
5       believe that would keep production going in  
6       particularly mature fields for longer periods of  
7       time.

8               We need to prohibit the utility from  
9       assessing local transportation charges on gas  
10      moved from storage in cases where the utility's  
11      already been paid to move that gas into storage.

12             Maximize the usage of all gas produced  
13      in California by providing incentives for the  
14      development and for many of the blending  
15      facilities designed to bring gas inventories that  
16      fall below utility pipeline specifications into  
17      compliance.

18             That's a big issue, particularly in  
19      northern California. And producers at this gas  
20      price can certainly find innovative ways to blend  
21      up or blend down their gas to get it into the  
22      pipeline and meet utility specifications, given an  
23      opportunity to do so.

24             While it's not in the purview of the  
25      Commission to enact legislation, we believe that

1       and encourage you to support the creation of a tax  
2       credit to California producers and/or generators  
3       where gas produced in California is used to  
4       generate electricity in California.

5               We believe we need to require utilities  
6       to allow producers access to fee property,  
7       easements and rights-of-way to install pipelines,  
8       to tie into the utilities' pipelines.

9               We need to authorize utilities to  
10       exercise their eminent domain authority where  
11       necessary to accommodate a connection, even if  
12       that means just in a short period of time during  
13       this gas supply crisis. We believe that's a  
14       critical issue.

15              We'd like to standardize the city and  
16       county permitting process for natural gas wells,  
17       pipeline installation and well interconnections by  
18       requiring all permit applications to be acted on  
19       within three weeks.

20              We'd like to eliminate the 50 mcf a day  
21       rule which prohibits the ability of a producer to  
22       deliver gas from a well that produces less than 50  
23       mcf gas a day. This law is unique to California  
24       and works to artificially constrain the production  
25       of new California resources.

1                   We need to promote policies that allow  
2           the producer the flexibility to deliver their gas  
3           to alternate markets when a utility pipeline is  
4           shut and/or curtailed. That's different from my  
5           previous comment in that there have been several  
6           recent instances where producers have found  
7           themselves with the possibility of delivering  
8           their gas to other markets when pipelines have  
9           been shut down for maintenance reasons or other  
10          reasons, but have been specifically prohibited  
11          from doing that by the utilities.

12                   Current law essentially discourages this  
13          practice by allowing the utility to assess stiff  
14          financial penalties when the producer seeks to  
15          deliver their gas elsewhere.

16                   I know this is a long list, but I think  
17          you should hear these issues, because they haven't  
18          been aired in this kind of a forum over the last  
19          five or six years. And I know you all are paying  
20          very close attention to these issues these days,  
21          and we appreciate it.

22                   We need to create new tax and financial  
23          incentives that encourage landowners to provide  
24          rights-of-way and easements on their property for  
25          new natural gas pipelines. Specific suggestions

1       might include providing property tax relief,  
2       making easement payments nontaxable income, and  
3       encouraging new field development with tax credits  
4       for higher risk oil and gas wells. Maybe those  
5       wells that are outside of 15 division of oil and  
6       gas boundaries.

7               And finally on my list, the CEC and the  
8       PUC should conduct a thorough evaluation of  
9       whether adequate pipeline capacity exists to  
10      accommodate increased production from new field  
11      discoveries, like East Lost Hills, petroleum down  
12      there, as well as more mature fields that could be  
13      exploited by new technology to produce more gas  
14      such as the Lathrop and San Joaquin County gas  
15      fields, which are south of us, and the Rio Vista  
16      and Grimes fields.

17             As I said, CIPA is currently working on  
18      many of these issues legislatively. My written  
19      testimony addressed each one of these pieces of  
20      legislature, so I won't go over them.

21             I did want to talk about one particular  
22      piece of legislation, and that is AB-1234, which  
23      facilitates the implementation of elements of the  
24      Gas Accord, because that is specifically  
25      referenced in your report, not the bill, but the

1 Gas Accord issue.

2 This bill creates terms and conditions  
3 under which PG&E is required to auction is  
4 gathering systems to interested producers. For  
5 those who may not know this, California is the  
6 only gas-producing state in the nation in which  
7 the utility owns the gathering lines.

8 These lines should be sold to producers  
9 who are interested in the fields, as I've said  
10 before. From the text of your draft it appears  
11 that the Commission is encouraging independent  
12 companies to assume control and operation of the  
13 gathering lines. And, again, CIPA members would  
14 like the opportunity to own those lines  
15 themselves.

16 In addition to the legislation which  
17 again is addressed in the testimony, there are  
18 three other issues that I think warrant mention in  
19 the final report.

20 The first is kind of unique to the oil  
21 industry, and that is that the San Joaquin Valley  
22 producers, heavy oil producers particularly, have  
23 a great deal of -- need a great deal of energy to  
24 produce oil. They need natural gas, they need a  
25 plentiful and reliable supply of gas, which they

1       are not getting right now.

2                   And then in turn they produce product  
3       that is used, heavy oil that is used in our state,  
4       in our refineries, that does not have to be  
5       imported from foreign oil-producing countries.  
6       And as a byproduct of that many of them deliver  
7       electricity into our system.

8                   Well, those folks who are not able to  
9       get access to those natural gas supplies than  
10      cannot produce that electricity, typically QF  
11      arrangement, which disadvantages California  
12      consumers. And then they cannot produce the oil  
13      that California refineries like to run.

14                  California produces about 40 percent of  
15      the oil it uses. And we believe this is a  
16      significant issue that is about to rear its ugly  
17      head. Our statistical reporting ability has about  
18      a three- or four-month lag time. And we are now  
19      at the point at which we believe you will see  
20      significant drop offs in heavy oil production in  
21      the Valley.

22                  So, yes, it's an oil issue, but it's  
23      also a gas issue. And those producers need that  
24      reliable supply of gas, too, to continue to  
25      produce that oil.

1                   Second, every effort should be made to  
2           locate, identify and incentivize production of  
3           stranded natural gas resources. By stranded  
4           natural gas, that could mean production in  
5           northern California area, or southern California  
6           area, but typically stranded gas, as we've  
7           identified it, is associated gas production, often  
8           in significant quantities, that could be used for  
9           distributed generation, could be used to run the  
10          leases, the operation of these producers.

11                   But for one reason or another, cannot be  
12          used, either because of gas quality issues or air  
13          emissions issues. In 1984 the Commission did a  
14          report looking at stranded gas. And we have a  
15          copy of that, and are in the process of updating  
16          that. We'd be pleased to supply a final copy of  
17          that to the Commission.

18                   But there are significant resources out  
19          there, particularly at this gas price, that could  
20          be brought to bear to help solve not all the  
21          problems, but a significant portion of them.

22                   Then finally, CIPA, SoCalGas and the  
23          California Air Resources Board are working  
24          together to resolve an issue of particular concern  
25          to south state producers in the San Joaquin Valley

1       and the L.A. Basin, and along the coast.

2               Without going into a great deal of  
3       detail, essentially there's associated gas  
4       production, some nonassociated gas production,  
5       that is out of compliance with CARB specs for  
6       ethane and other constituent components.

7               And we are working with SoCalGas and  
8       working with CARB to identify where that gas is  
9       coming from, and identify ways in which the impact  
10      on natural gas vehicle fueling stations will be  
11      felt.

12              We believe we're going to be successful  
13      there, but we want to bring it to your attention  
14      because it's not only potentially, you know, if it  
15      can't be worked out it potentially will not only  
16      impede California gas production, but also the oil  
17      production that goes along with it.

18              So, in many cases, as you've seen, the  
19      oil and gas production is inextricably linked, and  
20      along with the incentives, even though this is a  
21      natural gas supply issue report, should be  
22      mentioned in the final report.

23              Finally, CIPA is working with natural  
24      gas producers to establish a sister organization,  
25      tentatively called the California Natural Gas

1 Producers Association, which we hope you'll see  
2 before you in a very short order, which will  
3 address many of these issues that I addressed  
4 today. But with a specific focus on natural gas  
5 producers.

6 I appreciate the opportunity to come  
7 before you today and raise many of these issues.  
8 I have a copy of my final report, and would be  
9 willing to take any questions that you might have  
10 at this time.

11 PRESIDING MEMBER MOORE: Just one quick  
12 question, and then I'm going to ask what the  
13 timing will be on the written comments.

14 You indicate that you're interested in  
15 making some of these investments, given gas prices  
16 that we're seeing.

17 MR. KRAMER: Right.

18 PRESIDING MEMBER MOORE: Gas prices are  
19 falling.

20 MR. KRAMER: Right.

21 PRESIDING MEMBER MOORE: Or have been  
22 recently. I'm not sure what the outcome is going  
23 to be -- see a higher level than what we're seeing  
24 today in the near term.

25 At what level do you cease to be

1 interested in making some of those investments?

2 MR. KRAMER: I think it's geographically  
3 and individual producer specific. I don't want to  
4 put a particular peg on it. It just depends on  
5 where the gas is, what the quality is, what the  
6 quantity is, you know, how close you are to a  
7 customer. And, of course, the price.

8 California producers have historically  
9 received lower gas prices than producers from  
10 other states. Now we're seeing the flip side of  
11 that. We don't believe that's going to last  
12 forever. But, certainly during the time of  
13 relatively higher natural gas prices we believe a  
14 lot of infrastructure and other investments can be  
15 made and will be made, in addition to new wells  
16 being drilled, that will advance the supply issues  
17 that were talked about in the report.

18 PRESIDING MEMBER MOORE: And when might  
19 you be submitting some written comments to us?

20 MR. KRAMER: Got them right here.

21 PRESIDING MEMBER MOORE: Pretty rapidly.

22 (Laughter.)

23 PRESIDING MEMBER MOORE: A question,  
24 Jim?

25 MR. BOYD: Quick question, Mr. Kramer,

1       Dan, if I might.

2               MR. KRAMER: Yeah.

3               MR. BOYD: Like you said earlier, you  
4       don't get a forum like this, or an opportunity  
5       like this, although I'm very familiar (inaudible).  
6       I'm going to raise just a couple questions.

7               MR. KRAMER: Okay.

8               MR. BOYD: The issue of delays in the  
9       interconnections. You said you've been, quote,  
10      "complaining about that for ten years" unquote.

11              And the second somewhat associated  
12      question, the gathering systems, which I know has  
13      been hanging around for years and years and  
14      years --

15              MR. KRAMER: Yes.

16              MR. BOYD: -- without a lot of action.  
17      Do you have any comment you'd like to make or  
18      explanation you can offer up as to why these have  
19      been hanging fire for so long?

20              MR. KRAMER: On the first point, quite  
21      frankly, there hasn't been a whole lot of  
22      attention on gas supply issues when gas supply was  
23      plentiful and prices were not only low, but lower  
24      than other states.

25              And so there wasn't a rush or demand to

1 address the issue, to be very honest.

2 I would like to say, though, and if I  
3 didn't say it in my comments, that PG&E and SoCal,  
4 we are working together with them on many of these  
5 issues. And hope to address them not through the  
6 legislative process, or not through the regulatory  
7 process, but through either MOU or understandings  
8 that can be put into writing and may be blessed by  
9 the CEC or blessed by the CPUC at some point in  
10 the future.

11 But we appreciate all of the attention  
12 to these issues, what seems to producers all of a  
13 sudden. We welcome that, and hope that there is  
14 continued attention on these issues moving  
15 forward.

16 On the Gas Accord issue, producers  
17 believed they had an agreement with PG&E in 1996,  
18 to support not only the divestiture of the gas  
19 gathering system, but also the granting or  
20 gifting, almost, of that system to a cooperative  
21 made up of northern California gas producers.

22 We believed, or producers believed at  
23 that time that transaction was going to take  
24 place. It has not. And for a variety of reasons  
25 we have continued to bring it up. And finally the

1       issue appears to be gaining some ground and  
2       getting some legs. Now this Commission is looking  
3       at it, and the PUC is now examining it with a  
4       finer tooth comb, and we appreciate the increased  
5       scrutiny.

6               PRESIDING MEMBER MOORE: Thank you very  
7       much. Let me just indicate that my intention is,  
8       again apologize for starting late, that was my  
9       fault and I'm sorry that we got off with that.

10              But I'd still like to be able to give us  
11       a little bit of a lunch break. And so somewhere  
12       around noon I'd like to break for about 45  
13       minutes, and then we'll come back and go on to the  
14       others. And we'll give everybody a chance to get  
15       your blood sugar back up, and not nod off.

16              I'm not going to cut anyone off in the  
17       middle of what they're talking about, but that's  
18       my target. So, with that, let me turn and ask Lad  
19       if he would like to come up and address us.

20              Mr. Lorenz, welcome.

21              MR. LORENZ: Thank you, Commissioner  
22       Laurie. I'm Lad Lorenz, Director of Capacity and  
23       Operational Planning for Southern California Gas  
24       Company.

25              My comments today are going to be a

1       mixture of comments on behalf of SoCalGas, San  
2       Diego Gas and Electric, and even to some extent,  
3       Sempra Energy. Sempra Energy is the parent  
4       company of SoCalGas and San Diego Gas and Electric  
5       that serves over 21 million customers in southern  
6       California.

7               We certainly appreciate the opportunity  
8       to provide comments on the staff's report. First  
9       I want to applaud the effort of the staff work  
10      that went into the report. It's certainly an  
11      outstanding effort.

12             And I should point out that while my  
13      comments are probably going to seem critical, that  
14      we have addressed a number of these comments in  
15      private with the staff.

16             Nonetheless, going to the first slide, I  
17      did want to point out that SoCal and San Diego, we  
18      do agree with the primary conclusions that are  
19      contained in the CEC draft report. And let me  
20      just go over what we think those primary  
21      conclusions are.

22             Certainly there's an abundant supply of  
23      natural gas in North America that should be  
24      sufficient to meet the demand both in California  
25      and in the west. There's an ample resource base

1       that can be taken advantage of.

2               Interstate pipeline expansions are going  
3       to be forthcoming and the report goes into a lot  
4       of detail about them, about the new interstate  
5       pipelines that are under way, and those market  
6       forces are spurring those expansions.

7               Last count there's over 8 billion cubic  
8       feet a day of proposed pipeline expansions in  
9       California. A little over double the capacity of  
10      the state as it exists today.

11              We don't believe all those expansions  
12      are going to be built, or even necessary to be  
13      built. But nonetheless, interstate expansions are  
14      going to be forthcoming.

15              The report indicates that the SoCal  
16      system is adequate to meet the demands for this  
17      year. We certainly agree with that. We're going  
18      to go into that in some more detail. The current  
19      infrastructure is adequate to meet the current  
20      demand, and we believe that gas demand upon the  
21      SoCalGas system, as is indicated in the report,  
22      for the state in total is going to be declining in  
23      the short term. So therefore adequate  
24      infrastructure is in place to meet the needs.

25              Intrastate expansions to create

1 additional slack capacity are underway. They  
2 should be supported in the report. We appreciate  
3 the support that the report does provide with  
4 regard to these expansions that are planned on the  
5 SoCalGas and San Diego systems.

6 The current backbone transmission  
7 capacity of the system in southern California is  
8 3500 MMcfd of firm capacity and another 200  
9 million a day of interruptible capacity.

10 The maximum sendout the system has ever  
11 seen occurred last year of 3125 MMcfd, sent out  
12 annual daily average. And the projected sendout  
13 this year is about 3400 MMcfd. So you can see the  
14 system's going to be fairly full, but nonetheless  
15 there's adequate capacity. We have 3700 existing  
16 capacity and 3400 on projected sendout. So while  
17 the system is going to be relatively full,  
18 nonetheless there's adequate capacity.

19 In addition to that there is significant  
20 storage resources that add to that transmission  
21 capacity to make the total deliverability of the  
22 system in southern California alone 6 Bcfd. So,  
23 the fact that we had some 8 Bcf sent out statewide  
24 is not particularly troubling to SoCalGas. We can  
25 meet a 6 Bcf day just in southern California. The

1 historical peak of SoCal's system has only been  
2 5.3 billion back in 1990 when our models indicate  
3 we can meet a 6 Bcf day if we had to.

4 And finally there hasn't been any  
5 curtailments on the SoCalGas system in over ten  
6 years, and certainly none are projected for this  
7 year or next winter. Again, evidence that there's  
8 adequate transmission capacity that exists on the  
9 system.

10 One of the concerns that I have about  
11 the report is the way it describes the ability of  
12 SoCalGas to provide service to its customers. The  
13 tone of the report seems to indicate that SoCalGas  
14 may have problems making it through this year  
15 without having to curtail customers.

16 A more accurate portrayal could be  
17 achieved by clearly pointing out the fact that  
18 there haven't been any curtailments of any  
19 customers on the SoCal system for over ten years.

20 SoCalGas is confident that they will  
21 have enough natural gas in storage to serve  
22 customers' needs this winter. In fact, the  
23 storage on the system is currently at about 51 Bcf  
24 in inventory, and we are well on the way to  
25 meeting the winter storage targets established by

1 the CPUC for core service.

2 Furthermore, we're confident in our  
3 ability to meet electric generation demand this  
4 summer. Although the system, as I've indicated,  
5 will be close to full. But this does underscore  
6 the importance of the SoCalGas proposals to sell  
7 the cushion gas from several of the storage fields  
8 which will further augment supplies to the benefit  
9 of customers in southern California. I'll get  
10 into that when I describe some of the capacity  
11 expansions that we have underway.

12 We are concerned about the discussion  
13 regarding the investment in infrastructure that  
14 occurs on page 36 of the report. The statement  
15 that quote "SoCalGas has used the rationale for  
16 bypass to justify its failure to begin making  
17 investments to eliminate bottlenecks on its system  
18 until April of this year" doesn't accurately  
19 reflect what has occurred.

20 SoCalGas had settled on a resource plan  
21 in its last biennial cost allocation proceeding  
22 before the CPUC. At that time no one envisioned  
23 the need to embark on a massive building spree  
24 because there was a lot of excess capacity along  
25 the system.

1                   As the chart indicates, this is a  
2                   historical look at capacity utilization of the  
3                   SoCalGas system. Going back to about 1994 you can  
4                   see the gray area, that's the amount of excess  
5                   capacity on the SoCalGas system.

6                   It is only very recently, in the very  
7                   far right-edge of the chart that capacity  
8                   utilization has increased substantially.  
9                   Basically it was during the summer of 2000 that  
10                  that level changed dramatically and capacity  
11                  utilization has gone up. Primarily due to the  
12                  exceedingly high electric generation demand that  
13                  has occurred on the system. And, again, due to  
14                  the one in 75-year drought condition that is  
15                  existing in the Pacific Northwest.

16                 SoCalGas has responded quickly with a  
17                 series of proposals for expansion. And they are  
18                 targeted with some very aggressive efforts on our  
19                 part and cooperation amongst the state and federal  
20                 agencies for completion this winter.

21                 We are further concerned with the  
22                 inference on that same page that the lack of slack  
23                 capacity on the SoCalGas system has cost customers  
24                 billions of dollars. This is simply not the case.  
25                 The real culprit, we believe, is the runaway

1        wholesale electricity costs and the FERC's unwise  
2        decision to uncap the secondary market for  
3        interstate pipeline capacity prices. Those are  
4        the major contributors to the increase of cost.

5                    Go to the next slide. As I say,  
6        currently we have a total storage inventory of  
7        about 51 Bcf; that's slightly ahead of what is  
8        contained in the CEC's basecase. Injections are  
9        occurring by both core and noncore customers  
10       basically proportional to the inventory  
11       reservations that they have on the system.

12                   SoCalGas does buy the gas on behalf of  
13       core customers and is responsible for core  
14       injections. Noncore customers are responsible for  
15       their own purchasing and storage decisions, but  
16       are taking advantage of the opportunities and are  
17       storing gas on the SoCalGas system.

18                   Another comment is that we believe that  
19       the CEC's high end-use case certainly is overly  
20       pessimistic with regard to the future for this  
21       year. That case shows only 17 Bcf of gas in  
22       storage by June 1. Clearly way behind where we  
23       are now. And that inventory never exceeds 30 Bcf.  
24       So my comment would be the discussions and  
25       recommendations based on that case should be

1       discounted or changed. That case just seems to be  
2       overly pessimistic, not reflective of the fact  
3       that we've had five months of experience on the  
4       SoCalGas system this year. Things look a lot  
5       better than that, even the basecase.

6               This is the -- go back one -- this is  
7       the storage chart indicating the progress that is  
8       being made on storage injections. I have on here  
9       a variety, but nonetheless you can see that  
10      storage injections have been occurring on a  
11      regular basis and we expect them to continue  
12      through the summer period.

13             There is adequate capacity to meet the  
14      needs of the electric generation customers, and  
15      still have capacity for some injection during the  
16      summer period. There could be some dip in total  
17      inventory as noncore customers make use of this  
18      gas that they have stored for the summer, and that  
19      would be expected.

20             The yellow dots on that page were  
21      SoCal's outlook for storage inventories this  
22      season based on the presentation that I made at  
23      the Energy Division workshop referenced in the  
24      comments earlier. That's the basecase assumption  
25      without impact of any expansions or without any of

1 the storage programs that were ongoing. In fact,  
2 we saw inventory reaching 60 Bcf, and our  
3 projection, you see, we're substantially ahead of  
4 that projection.

5 So customers are making use of the  
6 available pipeline space. And as long as parties  
7 make use of the available pipeline capacity,  
8 storage injections will occur and there won't be  
9 any problems on the SoCalGas system.

10 This table lists the capacity expansions  
11 that the CEC Staff report does support. We  
12 certainly appreciate that. I won't go through all  
13 these, but the first two are the storage programs.  
14 We would expect, as soon as we receive CPUC  
15 approval, to be able to take advantage of 10 Bcf  
16 from Montebello and 14 Bcf from Aliso and Goleta  
17 underground storage fields, for a total of 24 Bcf.

18 You add that to the current 50 Bcf in  
19 inventory, you're up to 74, 75 Bcf already in  
20 total inventory on the SoCalGas system.

21 In addition to that, there are three  
22 expansions planned on the SoCalGas system. Kramer  
23 Junction being the largest at 200 million a day  
24 interconnect with the Kern/Mojave system. And  
25 then smaller expansions at Wheeler Ridge, North

1       Needles and Line 85. Line 85 specifically  
2       accesses California supplies. It should allow us  
3       to continue to receive increased production from  
4       California production.

5               As Bill indicated, another one that  
6       isn't on this because it's already completed, is  
7       the Line 6900 expansion to San Diego Gas and  
8       Electric system. That will add 70 million a day  
9       of increased capacity on the San Diego system, and  
10      should certainly alleviate and we hope eliminate  
11      any curtailments that might occur this summer.

12             There have been capacity constraints.  
13      The San Diego system is a local system with regard  
14      to SoCalGas system. There have been some capacity  
15      constraints, and Line 6900 was designed to relieve  
16      those constraints. And hopefully will alleviate  
17      any potential for further curtailments.

18             The next series of slides deal with some  
19      of the issues that were specifically addressed.  
20      And you'll notice with regard to necessary  
21      regulatory changes that might be put in place,  
22      we're looking for rolled-in pricing, not  
23      incremental at-risk pricing for backbone  
24      expansions.

25             SoCalGas is not yet guaranteed any cost

1 recovery for the \$50 million in backbone  
2 transmission investments that it is making. We  
3 decided to proceed with those investments without  
4 seeking to include those costs in our rates until  
5 our next cost of service general ratecase  
6 proceeding.

7               You will recall that SoCal's last major  
8 expansion was the Wheeler Ridge expansion, and  
9 that was an incrementally price, at-risk facility.  
10 And we're looking for a different rate treatment  
11 and would appreciate the support of the  
12 Commission.

13              We believe that if these expansions are  
14 being built in order to create additional slack  
15 capacity, is what we firmly believe, and that the  
16 purpose of slack capacity is to produce lower  
17 prices for everyone. That's what the staff  
18 believes the report emphasizes. And all customers  
19 are going to benefit from those lower costs, and  
20 all customers ought to share in cost of those  
21 expansions.

22              I'd next like to address the incentives  
23 with regard to noncore use of storage. Contrary  
24 to what is in the CEC's draft report, we believe  
25 there are sufficient incentives already in place

1 to encourage noncore customers to utilize storage.

2 Both core and noncore customers have  
3 already filled about 50 percent of their purchase  
4 storage rights, a total of over 51 Bcf, as I've  
5 said. Even at today's levels we have adequate  
6 storage in southern California. We have more  
7 storage in southern California today than what  
8 northern California does when their fields are  
9 completely full.

10 There is a portion of the report that  
11 should be clarified to address the inaccuracies in  
12 the amount of storage available in the Pacific Gas  
13 and Electric service territory. Contrary to what  
14 the report claims, PG&E doesn't have 98 Bcf of  
15 working storage capacity. In fact, they only have  
16 about 40 Bcf that can be cycled -- apparently due  
17 to injection limitations on their system.

18 But even if the Wild Goose facility is  
19 to be completed, or increases the size, if Lodi is  
20 built, northern California would have  
21 significantly less storage than, have about 94  
22 Bcf, than SoCalGas will have on its system at 120  
23 Bcf after the expansion.

24 The recommendation with regard to  
25 needing additional storage doesn't seem to be

1       appropriate, given that not all the existing  
2       storage is being utilized on the system.

3               In fact, although we have 70 Bcf of  
4       storage for core customers, the core doesn't  
5       actually need that amount of storage to meet their  
6       needs.

7               Further, the report declared that  
8       storage fields were stressed in southern  
9       California. We didn't see any stress in terms of  
10      the operation of our storage fields, and we  
11      withdrew gas from storage to meet demand on the  
12      system without any problems. And accordingly, the  
13      term stressed in terms of the operation of our  
14      storage fields doesn't seem to be appropriate.

15              With regard to encouraging California  
16      gas production, California production into the  
17      SoCalGas system has increased, has in fact  
18      increased fairly dramatically -- from less than  
19      300 MMcfd a few years ago to over 400 MMcfd today,  
20      primarily the result of increased production from  
21      the Elk Hills field.

22              The 40 million a day expansion that  
23      SoCal proposes --

24              (End tape 1B.)

25              MR. LORENZ: We are taking steps to

1 encourage California production.

2 SoCalGas and PG&E have a policy of  
3 maintaining 15 to 20 percent slack capacity on the  
4 system. As I showed in the previous chart about  
5 capacity utilization, we have maintained 15 to 20  
6 percent excess capacity in slack capacity on the  
7 system historically.

8 It was that unanticipated increase in  
9 demand due to that 1 to 75 year drought that has  
10 dramatically reduced the slack capacity that was  
11 planned for both of our systems.

12 The problem is that slack capacity has  
13 ever diminishing returns, and ever increasing  
14 costs. Unfortunately, the CEC report doesn't  
15 provide any guidance on how much slack capacity is  
16 enough. The CEC report doesn't provide any  
17 practical advice on how to deal with the  
18 imperfections of demand forecasts.

19 If we're going to base slack capacity on  
20 demand forecasting, then we need to be able to  
21 deal with the vagaries associated with demand  
22 forecasts. We believe there are preferable  
23 solutions to building slack capacity into the  
24 basic demand forecasts. I'll go into that a  
25 little bit later.

1                   One comment I would like to make is we  
2           believe that the proposed policy on curtailment,  
3           that is curtailing the least cost -- excuse me,  
4           the least efficient electric generators first on  
5           the system would not necessarily lead to the  
6           greatest electric reliability.

7                   A better policy and one that is being  
8           addressed in the CPUC's proceeding on curtailment  
9           policy, a better policy is one that curtails all  
10          electric generators on an equal basis, a pro rata  
11          method that limits gas to all electric generators  
12          that would allow those generators to shape their  
13          generation profile based on gas availability to  
14          meet electric demand.

15                  This method is also fairer in that it  
16          does not beg the question of how to determine what  
17          is the most efficient plan.

18                  For example, a high heat rate combustion  
19          turbine that can start up quickly and run only  
20          during peak periods and then shut down may use  
21          less gas and therefore be more efficient than a  
22          lower heat rate steam plant that must remain on  
23          all night just to ramp up to meet those peak  
24          loads. So the recommendation with regard to  
25          (inaudible) needs to be revisited in the report.

1           Another concern is the table that occurs  
2           on page 78 in terms of supply shortage. It refers  
3           to San Diego Gas and Electric's system; it doesn't  
4           accurately reflect how that system operates.

5           That system is basically a (inaudible)  
6           system; that is it is designed and able to meet  
7           hourly loads if they exceed hourly capacity. San  
8           Diego will not have a supply shortage just because  
9           demand exceeds capacity at the peak hours because  
10          we graph the system in order to continue to serve  
11          the needs of the market.

12          The demand load is served by the use of  
13          gas that has been packed in the system during the  
14          hours that the load was less than capacity.  
15          Accordingly, Sempra would urge that the table be  
16          clarified, lest it be interpreted as saying that  
17          San Diego Gas and Electric needs additional  
18          capacity of 12 million a day will eliminate the  
19          shortages that exist on the system.

20          Turning back to the issue of slack  
21          capacity, and Bill tried to address this in his  
22          comments, and I appreciate it. It's a difficult  
23          question.

24          The next slide is what is adequate  
25          infrastructure on the system. Unfortunately, as I

1       said, the CEC draft takes no position on this  
2       important issue. Sufficient capacity to meet  
3       expanded needs of the customers, is that what  
4       would be considered adequate infrastructure. In  
5       effect, you have no slack capacity during peak  
6       use. That's basically where we are right now.

7               We have adequate infrastructure to just  
8       meet the peaks under some very adverse conditions,  
9       a 1 in 75 year drought, and a 20 percent colder  
10      than normal winter last year on the system, and  
11      still we've met all the demands in the system.

12             But, you're right, capacity is going to  
13      be tight during those unusual events, if that is  
14      your planning criteria.

15             Should we build capacity to meet all  
16      demand scenarios, and therefore have large slack  
17      capacity during most years? That's basically the  
18      system we had ten years ago when, as Bill  
19      indicated, the system was over-built. We did wind  
20      up with significant amounts of slack capacity on  
21      the system. And had to deal with excess capacity  
22      costs, which I've spent a good portion of my  
23      career dealing with excess capacity costs and  
24      stranded costs on the system. That isn't an issue  
25      that I care to revisit.

1                   We believe that the best approach would  
2           be to base the decision with regard to  
3           infrastructure on long-term contractual  
4           commitments with capacity rights. We would urge  
5           the Commission to require electric generators to  
6           subscribe for capacity, both interstate and  
7           intrastate capacity, in order to meet their needs.

8                   Unfortunately, we don't have a  
9           regulatory structure in southern California that  
10          allows customers to subscribe for capacity,  
11          intrastate capacity, backbone transmission  
12          capacity, like they do in northern California.  
13          That does require unbundling and restructuring in  
14          southern California. That is a proposal that is  
15          before the CPUC in the gas industry, restructuring  
16          proceedings that Richard Meyers mentioned. One  
17          that we would encourage this Commission to  
18          support.

19                  There's a comprehensive settlement in  
20          that proceeding supported by 26 parties, many of  
21          which are in this room today. That addresses that  
22          issue of how to obtain firm, intrastate backbone  
23          transmission rights in the SoCalGas system. We  
24          would urge the CEC to get involved in that  
25          proceeding, make their position known, and that is

1       the appropriate mechanism and one that would  
2       increase the reliability and the working of the  
3       system to a very large extent.

4               Let's talk about further expansions on  
5       the SoCalGas system. We believe they should be  
6       based on market needs, not necessarily on the  
7       interstate pipeline capacity expansions.

8               The interstate expansions that are going  
9       to be built are going to serve a lot of customers  
10      directly. They will not necessarily need access  
11      to the SoCalGas system.

12              The amount of excess or slack intrastate  
13      capacity that should be constructed, should be  
14      determined by the CPUC in a current proceeding  
15      that is going on.

16              One of my final concerns is whether the  
17      recommendation to create yet another level of  
18      government review for short- and long-term  
19      capacity needs is really necessary. Sempra Energy  
20      believes that there are ample forums, and  
21      particularly the one I've listed here, that can be  
22      used for this purpose.

23              The PUC is addressing, currently  
24      addressing most of the issues raised in the staff  
25      draft report regarding the SoCal and San Diego

1       system in that investigation. And we urge the CEC  
2       to get involved in that proceeding.

3               All interconnections with the SoCalGas  
4       system can be accommodated; however, downstream  
5       take-away capacity from those points should be  
6       based on what is the market needs of the  
7       customers. And we believe that allowing those  
8       customers to contract for firm capacity rights is  
9       the best way to determine that market need.

10              So we would see some local transmission  
11       expansions that will be likely on the SoCalGas  
12       system, but not major further backbone  
13       transmission expansions. Based on what we have  
14       seen our projections agree with the CEC's  
15       forecast, gas demand on the SoCal system and in  
16       gas demand on the state isn't going to decline  
17       between now and 2005. How much it's going to grow  
18       between 2005 and 2010 we believe should be looked  
19       at later. Those long-term forecasts are very  
20       unreliable.

21              That completes my comments. Thanks very  
22       much.

23              PRESIDING MEMBER MOORE: Thank you, Mr.  
24       Lorenz. Very comprehensive and we appreciate it  
25       very much. Further questions? I thank you.

1 All right, well, true to what I said  
2 before, it's five after 12 now. Can we reconvene  
3 here at ten till, and I'll tell you what, why  
4 don't you come back at 1:00. And we'll begin this  
5 again.

6 Thank you.

7 (Whereupon, at 12:05 p.m., the hearing  
8 was adjourned, to reconvene at 1:00  
9 p.m., this same day.)

10 --o0o--

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

1 AFTERNOON SESSION

2 --o0o--

3 MR. BUCHNER: -- somewhat, and as we see  
4 the demands we also see prices spike.

5 Looking ahead, longer term, what we  
6 believe is that we will need additional  
7 infrastructure, backbone, storage and local  
8 transmission. And the outlook for the 2003 to  
9 2007 timeframe is we would anticipate maybe 200 to  
10 500 a day of backbone capacity additions.  
11 Possibly 250 to 350 a day of storage withdrawal  
12 capacity additions.

13 That will be somewhat dependent upon  
14 what happens with the competitive storage  
15 providers of Wild Goose and Lodi in northern  
16 California. But we can see a need for 250 to 350  
17 of additional withdrawal capacity.

18 And then at the local transmission level  
19 we have a couple of things. One is that with the  
20 amount of new electric generation coming on line  
21 we are having to make reinforcements to our local  
22 transmission system to accommodate the needs of  
23 those new plants.

24 And we're also looking at some possible  
25 changes to the reliability planning criteria we

1 use for local transmission. And I'll get into  
2 that a little bit later.

3 Looking forward at the outlook for gas  
4 demand and the through-put on our system our  
5 through-put is shown on the pie chart in terms of  
6 mix. And I think what's important on this chart  
7 is to recognize that in our off-system market in  
8 year 2000 power generation represented about 37  
9 percent. If you look at this year, it would be  
10 about 300 million a day higher, and that  
11 predominately is electric generation. So that  
12 would jump up almost another 10 percent this year.

13 On top of that, when you look at the  
14 off-system market, while we don't know  
15 specifically where that gas is being used in terms  
16 of the end-uses, it's primarily southern  
17 California, and we believe that much of that is  
18 probably also associated with electric  
19 generation. So, a majority of through-put on  
20 our system is electric generation.

21 The next slide is just a quick look at  
22 last year and this year to further illustrate  
23 there's also a high load factor that we would  
24 envision for our system this year. And you can  
25 see that there are a few months where we're

1       projecting to have some reserve capacity. But in  
2       most months we're going to be operating fairly  
3       close to our maximum capacity this year.

4               As Mr. Lorenz of SoCal described, this  
5       is an extremely unusual year.

6               Looking further out, and I'm going to  
7       focus now on electric generation, because that is  
8       the market that probably has the greatest  
9       uncertainty associated with it, and will have the  
10      greatest impact on our infrastructure needs.

11              You can see on the chart that from '98  
12      to through 2000 we generally averaged somewhere  
13      close to 700 MMcfd, with a range of between 450 up  
14      to around 900 MMcfd, for gas-fired generation.

15              Looking at this year we're projecting  
16      somewhere around 1250 MMcfd as an annual average  
17      through-put for electric generation. That just  
18      really illustrates how extreme this year is.

19              Going forward with all the new  
20      generation that's being built across the WSCC, you  
21      know, we see that gas-fired electric generation is  
22      extremely uncertain in terms of the overall level.  
23      Our current projection would suggest that over the  
24      next several years we could very well drop down  
25      into the 700 million a day range.

1                   And what's driving that is that a lot of  
2           the -- or all of the generation being built that's  
3           gas fired is substantially more efficient than the  
4           older generation.

5                   And so, for a number of years what we're  
6           likely to see is that the increased efficiency  
7           will offset the growth in power consumption. And  
8           so you don't see a trend, an upward trend until  
9           you start getting out in the 2006 timeframe.

10                   And if we were to extend this chart,  
11           then you would see an upward trend.

12                   I would underscore that there's  
13           tremendous uncertainty as to the absolute level of  
14           gas-fired through-put for us because the gas  
15           generation, gas-fired electric generation market  
16           is a western U.S. market. And we are greatly  
17           affected by what's happening in terms of hydro  
18           generation elsewhere, and also how much new  
19           generation is built in other areas of the WSCC.

20                   The dry scenario that I have represented  
21           on this chart is roughly somewhere around a one-  
22           in-ten type of scenario. And my understanding is  
23           that the assumptions that went into generating  
24           this scenario was roughly an 80 percent  
25           availability of Pacific Northwest hydro generation

1       and about a 70 percent availability of northern  
2       California hydro generation.

3               So it's not as extreme as this year, but  
4       you can see that the demands under the scenario  
5       are, you know, within 100 to 200 a day of what  
6       we're seeing this year.

7               Let me switch gears just slightly here  
8       and we'll talk about capacity guidelines. This is  
9       an area that is of great importance today.

10              Currently for backbone capacity planning  
11       the last standard that's been issued, which was  
12       from the CPUC decision 90-02016, suggested that a  
13       10 to 20 percent slack capacity of a cold year  
14       demand would likely be an appropriate standard to  
15       maintain adequate reserve to allow more  
16       competition and to help hold prices down.

17              For the local transmission system PG&E  
18       currently uses two standards. One is what we call  
19       the abnormal peak day, and that represents a  
20       condition consistent with the coldest day of  
21       record experienced on the PG&E system, which we  
22       estimate would have about 1 in 90 year recurrence  
23       interval.

24              And under that condition we would only  
25       plan to be able to serve the core market. And

1       this is local transmission planning.

2               So under that scenario, if we were to  
3       experience this event, we would not plan to have  
4       adequate local transmission capacity to serve  
5       anything but the core market.

6               As a consequence, however, based on the  
7       way gas systems are built, even under that  
8       scenario it would be likely that a portion of the  
9       noncore market could be served because of its  
10      proximity to the backbone system.

11              The other standard that's applied for  
12      local transmission planning is the cold winter  
13      day. And that standard essentially represents a  
14      day that has a load, the core demand is about 75  
15      percent, as great as on an abnormal peak day. And  
16      the likelihood of that event is about once every  
17      three or four years.

18              Under that scenario we would plan today  
19      to have an adequate local transmission capacity to  
20      serve both the core market and the noncore market,  
21      connected in the local transmission systems.

22              Both of these planning standards are  
23      evaluated by our engineers. And whichever  
24      scenario is the controlling factor is the one  
25      that's used to guide investment decisions in the

1 local transmission system.

2 Looking at storage, the primary driver  
3 for storage investments historically has been  
4 satisfying core demand in extreme winter  
5 conditions. And that would include both the  
6 abnormal peak day and cold weather conditions.

7 Out of all of this, the single greatest  
8 issue in our minds is that currently standards do  
9 not really capture changes in the gas market in  
10 California today. The noncore market, by and  
11 large, no longer has alternate fuel backup. And  
12 this has become especially clear when we look at  
13 electric generation and a lack of fuel oil.

14 And so we believe that there is a need  
15 to update the capacity planning guidelines to take  
16 into account these new realities.

17 Turning to slide ten, this is a look at  
18 the backbone system. And I'm going to focus the  
19 next several slides on backbone.

20 This is where I think the change with  
21 electric generation is really going to become  
22 clear. If we were to apply the current cold day  
23 planning standard, or cold year demand standard  
24 for backbone you can see that in a cold year we  
25 would expect to be operating at somewhere around

1       80 percent of capacity.

2               That would suggest that we have at least  
3       20 percent of slack capacity. And you might say,  
4       we're okay, we don't need to add capacity.

5               But if we look at the next slide on page  
6       11, this looks at the problem a little  
7       differently. What we've done is we've said but in  
8       a dry year, given the potential for increases in  
9       electric gas-fired electric generation demand we  
10      see that an annual average demand could increase  
11      dramatically and result in an overall demand level  
12      much higher than in a cold year.

13              In this instance it would show that we  
14      would be operating at around 95 percent capacity.  
15      And that's not too far off of where we are this  
16      year.

17              Now, this would suggest if we were to  
18      have a 15 to 20, or 10 to 20 percent slack for  
19      reserve margin as a standard, this would suggest  
20      that we should be adding capacity.

21              Looking at page 12 you might ask, well,  
22      so why a dry year reserve margin. And there are a  
23      number of points, but a couple that I would really  
24      focus on is that there's tremendous uncertainty  
25      regarding the electric generation demand. And

1       it's very very difficult to forecast today,  
2       especially given that the market is driven by what  
3       happens for us at WSCC.

4               Another key point is that maintaining  
5       reserve margin really does help keep prices down.  
6       I think we've observed this year that northern  
7       California gas prices have been substantially  
8       lower than southern California, and we believe  
9       that a portion of that is certainly attributable  
10      to the relative amount of reserve margin that  
11      we've had compared to southern California.

12             In general the cost of capacity, the  
13      cost factor on capacity for PG&E is very  
14      inexpensive relative to the risk of commodity  
15      price increases. So, we could increase capacity  
16      very inexpensively relative to the commodity  
17      cost.

18             I think it's important to note that this  
19      is true for about the next 500 a day of capacity  
20      additions on our backbone system, but beyond that  
21      then we would be faced with increasing capital  
22      investment for success of capacity increases.

23             So it's not as simple as saying, you  
24      know, it's cheap, just build it and maintain the  
25      reserve capacity. I think that the utilities are

1       very much concerned that especially when we get  
2       into large amounts of capital investment required  
3       for expansion that then we need to have some  
4       assurance that we're going to be able to recover  
5       these funds.

6               And I think that how you view reserve  
7       margins may change depending upon how costs for  
8       that reserve capacity change over time.

9               Looking at page 13 we've estimated what  
10      reserve margins might need to look like, or what  
11      additional capacity might be based on the  
12      (inaudible) we've just been discussing, and it  
13      shows that to maintain a 15 to 20 percent reserve  
14      margin we would need to add over the next say five  
15      to seven years, somewhere between 250 to 500  
16      million a day capacity on our backbone system.

17              The extent to which, you know, we're  
18      willing to do this, and we're actually proposing  
19      to expand our system by 200 than already, but the  
20      utilities are certainly very concerned about cost  
21      recovery issues.

22              We see the value of reserve margin. We  
23      think that our line 401 expansion back in the  
24      early '90s has brought, you know, tremendous  
25      benefits to California helping hold gas prices

1 down. But our willingness to continue to make  
2 capital investment for reserve margins will be  
3 somewhat dependent upon our ability to recover  
4 those costs.

5 Moving ahead, looking at the specifics  
6 of infrastructure improvements, I already  
7 mentioned that we're planning on adding 200 a day  
8 of capacity on our Redwood Path. This generally  
9 matches up with the open season results on the GTN  
10 pipeline to the north. And GTN also has an open  
11 season currently underway for additional capacity.

12 We've announced an open season of our  
13 own that would be subject to, or applicable to  
14 that 1.2 Bcf of capacity on our backbone system.  
15 Included in that is the 200 a day expansion in our  
16 plants.

17 When we look at the Redwood Path on our  
18 system it has been preferred market for many years  
19 because of the relatively low cost of supply on  
20 that Path. And as it happens, the cost of  
21 expansion on that particular path for PG&E is  
22 quite inexpensive. For \$35 to \$100 million we can  
23 expand to 500 a day. And if you compare that to  
24 the cost of building new pipe, that's quite a bit  
25 cheaper.

1                   When we look to the south on our Baja  
2                   path, we're faced with some challenges. Expansion  
3                   on that path generally requires us to parallel  
4                   existing pipeline because of the design of that  
5                   system. It's not -- we're not able to simply  
6                   increase it by adding compression like we can on  
7                   the Redwood Path.

8                   One of the questions that's come up is  
9                   well, if we didn't have to expand that system all  
10                  the way to Topock would it be less expensive. And  
11                  we haven't really evaluated that in any detail,  
12                  but in general if we were to only expand the  
13                  system from say the Daggett area or the  
14                  Bakersfield area northward, it would be less  
15                  expensive.

16                  And we're willing to look at that to the  
17                  extent that there's a serious intent to expand  
18                  capacity from the south.

19                  Turning to storage, we've looked at a  
20                  potential need to add 250 to 350 a day withdrawal  
21                  capacity into the future. And the driving factor  
22                  for this has been some work we've been looking at  
23                  to improve reliability for the noncore market.

24                  Under today's rules the noncore market  
25                  supply basically is diverted to serve the core

1 market when the core market runs short of supply.  
2 Currently we would estimate that that could happen  
3 once in every three or four years.

4 We've been looking at ways to firm up or  
5 not have to divert to noncore supply. And the one  
6 that we've been focusing on of late has been a one  
7 in ten year time criteria. That seems to make  
8 sense to us from an economic perspective, and  
9 feedback we have is that that may receive support  
10 in the market, as well.

11 To do that, if PG&E were to expand its  
12 withdrawal capacity to add 250 to 350 a day, it  
13 would cost about \$35- to \$50-thousand.

14 Associated with that expansion we would  
15 necessarily need to build what we call Line 57C.  
16 And that would be an additional pipeline that  
17 would be a connection from our McDonald Island  
18 storage field to our backbone.

19 The existing pipeline that is connected  
20 to McDonald Island is increasingly at risk because  
21 of the Delta and the islands that it crosses. And  
22 for sometime we have been looking at adding  
23 another line for reliability purposes, but we  
24 would not be able to expand our withdrawal  
25 capacity without that additional pipeline.

1                   Looking at local transmission, as I  
2                   mentioned we've been looking, we've been  
3                   evaluating a potential move to a one in ten year  
4                   capacity planning standard that would replace the  
5                   cold winter day type standard. And the one in ten  
6                   planning standard would probably be the driving  
7                   standard for investment if we were to adopt it.

8                   Getting there would cost somewhere  
9                   around \$63 million of capital investment. But  
10                  that would happen over a period of years. So you  
11                  can see it's relatively, it's not hugely expensive  
12                  to improve the reliability on the local  
13                  transmission system.

14                 A couple of other issues I wanted to  
15                 touch on. On page 19, one relates to noncore  
16                 storage. And the staff report suggested that one  
17                 possibility might be to rebundle storage. And we  
18                 really wouldn't support that.

19                 We're not sure, we just don't believe it  
20                 would make sense. The northern core of California  
21                 now has third-party storage providers. The  
22                 concept of rebundling doesn't work very well where  
23                 you have a competitive storage market.

24                 And we would say that also the gas  
25                 support structure that is in place today, both for

1 backbone and storage services, has been used  
2 working pretty well for northern California. And  
3 we continue to work with the parties, customers,  
4 shippers and regulators, in addressing issues that  
5 have arisen since we -- Gas Accord in March of  
6 '98. So we think things are actually working  
7 pretty well.

8 The other thing to keep in mind is that  
9 storage, in and of itself, is not a perfect  
10 replacement for pipeline capacity. So when we  
11 think of storage as the backup, think of it in the  
12 context of it's good for short-term backup, but  
13 it's not inexhaustible.

14 And so having adequate backbone reserve  
15 capacity becomes very important, you know, when  
16 you think about the role storage would play in  
17 providing reliability for a noncore market.

18 The other thing I'd like to touch on  
19 briefly is California gas production. I'm just  
20 going to make a few points today, I'm not going to  
21 try to address all the comments that have been  
22 made.

23 California gas production is somewhat  
24 outside of my area of expertise, but I do have a  
25 few comments I would like to make.

1                   One is that the sale of the gathering  
2           systems, I know that PG&E has sold a little bit of  
3           the gathering system. We have worked with  
4           producers and other parties to sell more of the  
5           gathering system. And a number of issues have  
6           arisen, including, you know, environmental  
7           concerns, term of reliability, and the fact that  
8           in a lot of areas it's difficult to know exactly  
9           what types of environmental issues might actually  
10          surface somewhere down the road.

11                   Also, there's about, as I understand it,  
12          about an 18-month process that we have to go  
13          through to sell assets. And that's a CPUC 851  
14          filing. And it's my understanding that that's  
15          also presented some difficulty for us in selling  
16          the gathering system; some producers don't seem to  
17          be very willing to go through this process. It's  
18          kind of an arduous process to go through.

19                   Turning to the issue of Btu, low Btu gas  
20          in California. We have worked extensively with  
21          the producing community to try to place low Btu  
22          gas wherever we can. And the issue is very  
23          simple. Low Btu gas, unless it's sweet, or unless  
24          the heating value is improved by the producer, can  
25          be mixed in our system, but it has to be mixed in

1 a way that the resulting heating content does not  
2 create safety issues in the gas system.

3 We have to maintain heating values  
4 within certain ranges. There are options to deal  
5 with low Btu gas. Unfortunately, most of these  
6 cost money. And so I think it really boils down  
7 to a case of economics. It's either it's going to  
8 cost something to improve the heating contents of  
9 the gas, or it's going to cost money to possibly  
10 build lines that route that gas over to parts of  
11 our transmission system that have higher through-  
12 put where it's easier to mix it. So I think that  
13 the whole issue of low Btu gas typically centers  
14 around economy.

15 One thing in response to well  
16 connections, I would say that PG&E has committed  
17 to producers that connect new wells within 45  
18 days. And I'm advised that currently the average  
19 length of time to connect is 39 days. So we are  
20 working very hard to get new production connected  
21 as quickly as we can.

22 PRESIDING MEMBER MOORE: Is that a  
23 change from historical times?

24 MR. BUCHNER: I really am not that  
25 familiar with the historical. I know that it's

1       been an issue over the years. I'm not sure what  
2       the performance has been over the long haul.

3               In conclusion, just reinforce that for  
4       the short run we have adequate capacity for a  
5       certain market. We don't see a problem for 2001.  
6       And in the long run we are going to need to add  
7       capacity probably in all areas, backbone, local  
8       transmission and storage.

9               And I would just say that many of the  
10       investments that we're looking at today have a  
11       fairly small impact on rates. And our rule of  
12       thumb that we use is for \$100 million of capital  
13       investment, it would have on average about 3 cents  
14       per decatherm impact on rates. And that's pretty  
15       small in a market where we are paying \$5 or \$10  
16       per decatherm for gas.

17               So, at least for now the relevant  
18       benefits of investment look pretty good compared  
19       to the alternative of the -- capacity market that  
20       drives up prices.

21               In closing, we are preparing to file our  
22       Gas Accord II application with the Commission.  
23       And we do expect that any of the infrastructure  
24       issues will be dealt with in that proceeding. We  
25       think it's a good proceeding because it involves a

1 wide range of parties, and it allow us to deal  
2 with a wide range of issues.

3 And infrastructure issues often get into  
4 who pays and what are the rates, and what is the  
5 appropriate amount of capacity and where. And we  
6 believe the Gas Accord to proceed would provide a  
7 forum for those issues.

8 I think I mentioned we've also announced  
9 an open season. We expect that we will be sending  
10 out the package to (inaudible) by June 12th. And  
11 our open season would conclude or close on July  
12 31st.

13 We're envisioning that that open season  
14 will allow shippers to also elect to commit to  
15 long-term contracts that would go well beyond any  
16 Gas Accord II timeframe. We know that one of the  
17 issues for the shipper community has been, or at  
18 least for California, has been the ability to  
19 enter into long-term contracts, your capacity.  
20 And that's especially important, I think, to the  
21 electric generators.

22 That concludes my remarks.

23 PRESIDING MEMBER MOORE: Have your long-  
24 term capital planning horizons changed in the last  
25 couple of years, so you might have been planning

1 forward five years, eight years, ten years for  
2 your expenditures -- those changed?

3 MR. BUCHNER: I'm not aware that we've  
4 really changed our planning horizons. What I  
5 would say is that the -- certainly there are time  
6 horizons for local transmission has not changed.  
7 That's an ongoing issue.

8 For backbone capacity planning, to put  
9 this in perspective, PG&E has made three major  
10 backbone additions in the last four years. We  
11 built, actually going back further than that, we  
12 built Line 300 from the southwest back in the  
13 1950s. We built Line 400 that brings gas from  
14 Canada in the 1960s. And then the next major  
15 increment of backbone capacity was built in the  
16 early '90s, Line 401.

17 So backbone capacity typically has come  
18 in very large chunks. And while we routinely look  
19 at the potential need for backbone capacity  
20 additions, we might look five, ten years out,  
21 especially for backbone capacity, it's not  
22 something that we add very often. And we feel  
23 we're in a good position today in that we can  
24 fairly readily add backbone capacity now in fairly  
25 small increments as the market needs it.

1                   PRESIDING MEMBER MOORE: Thank you, I  
2           appreciate your coming and taking the time today.

3                   MR. BUCHNER: Thank you.

4                   PRESIDING MEMBER MOORE: Plus you're  
5           going to submit other testimony?

6                   MR. BUCHNER: We'll have written  
7           comments on the staff report hopefully by the end  
8           of this week.

9                   When we conclude this proceeding I'll  
10          talk a little bit about time, as far as when to  
11          expect those (inaudible).

12                  PRESIDING MEMBER MOORE: All right. We  
13          have Brad Barnds, Calpine. Welcome, and I  
14          understand congratulations on (inaudible).

15                  MR. BARND: Thank you very much. Good  
16          afternoon. My name is Brad Barnds, I'm Vice  
17          President of Fuels for the Calpine Corporation  
18          (inaudible) relocated (inaudible).

19                  First I'd like to apologize, I failed to  
20          put Calpine or my name on this, these comments, so  
21          I apologize for that.

22                  I wanted to provide an overview and  
23          introduction (inaudible) new generation, but just  
24          kind of hit some of the highlights, as well as to  
25          bring to bear that Calpine is more than just a

1       builder and developer of power generation  
2       facilities in the west.

3               We do plan on building 9000 megawatts of  
4       generation in California and --

5               PRESIDING MEMBER MOORE:   Could I get you  
6       to speak a little closer to the microphone?

7               MR. BARND:   I think that the 9000  
8       megawatts of generation in California is actually  
9       on the light side.   We do intend to have in excess  
10      of 12,000 megawatts in the western United States.

11              We intend to be the largest independent  
12      power producer, and the most (inaudible) power  
13      producer in the United States.   We estimate now  
14      our forecast is to be producing in excess of  
15      70,000 megawatts in North America.

16              We were the first generator to sign  
17      fixed price contracts with the Department of Water  
18      Resources.   I think that was a very significant  
19      event for Calpine and for the state.   Indicates  
20      Calpine's interest in working with all  
21      constituents of California to assist in the energy  
22      crisis.

23              Being the largest power producer we have  
24      an early intention, I suppose, of being  
25      potentially the largest gas user in North America,

1 as well. Power demand in the west is probably  
2 going to be in excess of 2.5 Bcf on a daily basis.  
3 Nationwide, North American basis, our gas  
4 consumption will be approaching 10 Bcf a day.

5 I wanted to also bring to light that  
6 we're also a significant gas producer. Part of  
7 our portfolio is going to be met with equity gas  
8 reserves. We have a company, Calpine Natural Gas,  
9 which is in the marketplace securing long-term gas  
10 reserves in Canada and the U.S., and option  
11 (inaudible) Mexico.

12 Right now we have in excess of 1Bcf of  
13 gas as equity gas that we can call on. Most of  
14 that is up in Canada at the present time. We're  
15 also a significant gas producer in northern  
16 California, having approximately 45- to 50-  
17 thousand Btus per day of gas at our control,  
18 primarily in the Rio Vista field area.

19 And in addition to that, we also  
20 aggregate from a number of the smaller producers  
21 in the northern California production areas,  
22 bringing in excess of 100,000 MM Btus a day of  
23 locally produced California gas to our power  
24 plants.

25 How does that gas get to our power

1 plants? Through a private pipeline system that  
2 Calpine has assembled over the last several years.  
3 We've actually aggregated more separate private  
4 pipelines (inaudible) northern California,  
5 including the Shell pipeline, the Dow pipeline,  
6 the Sacramento River Gas System, and the pipeline  
7 that we called upon (inaudible) pipeline system.

8 This pipeline system is capable of  
9 delivering several hundred (inaudible) a day of  
10 gas to our power plants of which there are six.  
11 Three new merchant power plants, the Los Medanos  
12 Energy Center, the Delta Energy Center, Sutter and  
13 three QFs, (inaudible) I and II, and our existing  
14 (inaudible) facility.

15 So that's just to set the stage for  
16 Calpine. Our comments today are going to focus on  
17 the California intrastate capacity needs and the  
18 design criteria. This basically is composed of  
19 can we get the gas to the burner jets.

20 Secondly, I'd like to address interstate  
21 capacity to and in California. Can we get access  
22 to the gas reserves from the suppliers.

23 Thirdly, storage utilization for noncore  
24 customers, how can storage be used effectively,  
25 and how should that be paid for.

1                   And finally, California production, how  
2                   can we maximize --

3                   (End tape 2A.)

4                   MR. BARND: Currently there's about 2  
5                   Bcf of pipeline expansions that are in advanced  
6                   stages. This is not just an announcement, a press  
7                   release. These are pipeline expansions that have  
8                   actually gone forward to some form of binding  
9                   commitment. Again, that's going to leave 3.7 Bcf  
10                  of capacity that's still going to be needed if all  
11                  the new generation actually comes appear in the  
12                  marketplace.

13                  As a generator, these are our comments  
14                  from Calpine from the generation side, we face  
15                  obstacles in meeting our capacity needs. Above  
16                  all else, electric generators require low cost  
17                  reliable service.

18                  Calpine has maintained their commitments  
19                  to the State of California to provide long-term  
20                  reliable power. Long-term reliable power requires  
21                  reliable gas. In our estimation the existing  
22                  pipeline infrastructure isn't sufficient for our  
23                  needs.

24                  We need to have the ability to access  
25                  long-term firm capacity. That currently does not

1       exist. And (inaudible) was highlighted by PG&E  
2       that they do anticipate that future expansions are  
3       going to be required. That presently (inaudible)  
4       to know today how much firm capacity we can get,  
5       or at what rate.

6               Additionally, it's very difficult for  
7       Calpine or any other generator in northern  
8       California, to make long-term commitments without  
9       knowing whether the gas is going to show up on any  
10      given day. The one in three years, or something,  
11      is not acceptable from Calpine's perspective,  
12      meeting long-term commitments to deliver firm  
13      power.

14             And the complication on SoCal and San  
15      Diego system is that there's no system of firm  
16      tradable rights. I think that was highlighted by  
17      SoCal, as well.

18             Again, another issue for us as a  
19      generator is uncertainty of rates and market rules  
20      creates obstacles. It was highlighted in the  
21      report that there is a conflict between filling  
22      storage in the summer and moving gas to generators  
23      (inaudible). This is a conflict of obligations.  
24      Somehow we need to bridge the gap.

25             We also believe that there's a limited

1 gas on gas competition. There's insufficient  
2 pipeline capacity to move gas from the south to  
3 the north. And there's a lack of competitive  
4 alternatives, barriers to entry. These are  
5 largely historical regulatory regimes that have  
6 existed in the State of California that have  
7 hindered new pipelines, particularly interstate  
8 pipelines from coming into the state.

9 On the intrastate pipeline design  
10 criteria we would agree that we need to certainly  
11 take into consideration not only the winter, but  
12 the summer, as well. Both peaks are very  
13 important.

14 The draft report suggests regulatory  
15 approach to encourage or mandate slack capacity.  
16 One of our concerns is that by mandating slack  
17 capacity principally on the utility side may  
18 ignore, I suggest, may ignore cost causation  
19 principles. It may result in anti-  
20 competitiveness, meaning that there will not be  
21 encouragement for alternative pipelines to come  
22 into the state because the existing pipelines  
23 cannot be created on the utility side.

24 And it may be difficult to differentiate  
25 levels of service; create 20 to 25 percent slack

1 capacity.

2 In any event, slack capacity should  
3 include both inter- and intrastate capacity and  
4 storage. The market should be able to decide what  
5 is the most economic of those (inaudible)  
6 capacity.

7 And as has been stated by others, the  
8 market is responding, both interstate and  
9 intrastate, (inaudible) currently planned. We do  
10 think that open seasons as was being provided for  
11 by PG&E provides the right venue for customers to  
12 respond to market signals and conditions, and to  
13 determine what expansions are the most  
14 appropriate, making the most sense.

15 One of the things that's very important  
16 to Calpine is these open seasons and generally  
17 speaking is the rules must allow the ability to  
18 get to the necessary level of service. One of the  
19 issues we think may come out of Gas Accord II,  
20 (inaudible) open season of PG&E is that because of  
21 market sensitivities Calpine would not be in a  
22 position to acquire all the maximum capacity it  
23 would need to meet its generation demands.

24 Calpine may have (inaudible) 1 Bcf a day  
25 of gas demand in northern California, but because

1 of the open season rule or rules coming out of Gas  
2 Accord II, would only be able to get maybe 400,000  
3 or 500,000 (inaudible).

4 If that were the case, we're short,  
5 where would the gas come from. Who would be  
6 relied upon to make good on our promise to the  
7 State of California to deliver gas to the power  
8 plants to make power. It's just a regulatory  
9 inconsistency that for whatever reasons  
10 (inaudible) pursuit. But it doesn't help Calpine  
11 (inaudible).

12 In summary, a new interstate pipeline  
13 projects to and in California will come to bear.  
14 New projects will be built to meet electric  
15 generation, gas demand and growth in California.  
16 It will also, we believe, (inaudible) interstate  
17 pipelines in the State of California, in addition  
18 to (inaudible) by the utility will help to create  
19 some of the additional take-away capacity at the  
20 California border.

21 The benefits of interstate pipelines  
22 capacity allows the marketplace to obtain firm  
23 pipeline capacity, to meet the growing gas-fired  
24 generation demand we have for the electric  
25 generation market.

1           In addition to that, additional  
2 interstate pipeline capacity, whether it comes to  
3 the California border or all the way through and  
4 up into northern California, will help alleviate  
5 some of the upstream demand situations for the  
6 State of California by again mitigating some of  
7 the gas that gets dropped off in adjoining states.

8           The interstate pipeline capacity will  
9 allow or provide reliable firm transportation and  
10 a stable gas supply for electric generation. And  
11 encourage future project development in the State  
12 of California.

13           If there's a perceived risk being able  
14 to get gas on a reliable basis 24 hours a day,  
15 seven days a week, those who would build  
16 (inaudible) in California. Again, this new  
17 interstate pipeline could reduce the mismatch  
18 between delivery and receipt capacity at the  
19 California border. And we would suggest will  
20 provide the utility with additional transportation  
21 alternatives to meet core needs.

22           One of the interstate pipelines, and  
23 I'll try not to make this an advertisement, but  
24 Calpine, in a joint venture with Kinder Morgan,  
25 has announced a project from New Mexico going to

1 the California border, basically Needles and  
2 Topock, through that's phase I. This would be an  
3 interstate pipeline delivering 750,000 a day of  
4 gas supply to the San Juan Basin to the border.

5 And then from there northward, basically  
6 up through Kern County and then up the I-5  
7 corridor, we're calling on phase II, anywhere from  
8 1 Bcf to 1.5 Bcf a day, depending on how the  
9 market wants to construct this, to basically the  
10 Antioch/Pittsburg area.

11 What's interesting to note here is it's  
12 the longest pipeline route; it's over 6000  
13 megawatts of Calpine generation alone situated on  
14 this pipeline. This is one of those significant  
15 regions for the development, and this proposed  
16 project is in direct access of long-term gas on a  
17 firm basis, delivered on pipelines dedicated to  
18 meet electric generation needs in the State of  
19 California, for which Calpine is (inaudible)  
20 consumer gas.

21 Storage utilization by noncore  
22 customers. Calpine is a proponent of storage. We  
23 currently have announced we have a ten-year deal  
24 (inaudible) with Lodi Gas storage. We're also in  
25 the business of developing storage in our own

1 right on a proprietary basis.

2 However, the report suggests that  
3 rebundling utility storage somehow will encourage  
4 noncore use of storage. In our estimation  
5 generators or any other participant can go into  
6 the market and acquire storage and utilize it.  
7 Certainly that's what Calpine's intention is.

8 The problem with not going into storage  
9 (inaudible) and Calpine, the particular case,  
10 would be paying for the same thing twice.

11 We also think that rebundling storage is  
12 a utility function. It really is not just limited  
13 to generators, but all party participants should  
14 be looking at their incentives, including the core  
15 market.

16 And if you do rebundle storage this may  
17 present disadvantages to the development of  
18 additional third-party storage in the State of  
19 California. Calpine strongly supports  
20 infrastructure development and noncore incentives  
21 be in the market in order to get risk capital to  
22 the state.

23 Generators entering into long-term power  
24 sales contracts need long term, reliable gas  
25 supply. We've already said that. Calpine's

1 developing a diversified portfolio, gas from  
2 Canada, the Rockies, San Juan (inaudible) storage.

3 Critical to that is the need for  
4 flexibility. Power plants (inaudible) operate 24  
5 hours a day, but that doesn't always work. We  
6 need to have the ability to push gas to some other  
7 location, i.e., storage, or to get gas out on  
8 demand. This is in addition to the reliability;  
9 storage provide both, flexibility and reliability.

10 And I guess underlying all this we need  
11 the low cost gas.

12 Our belief is that storage development  
13 should be encouraged, whether it's utility or non-  
14 utility.

15 Increasing California gas production.  
16 Currently today California gas production is not  
17 being maximized. Currently, in Calpine's  
18 estimation, there's limited access to the  
19 transmission system. We have experienced delays  
20 in getting production on. I heard (inaudible)  
21 three months, and also cost (inaudible) \$30,000  
22 per well.

23 Largely related to gathering system, the  
24 inability for us to lower system pressure in order  
25 to maximize production. The inability or limited

1       ability to deliver low Btu gas to the system.  
2       There are apparently economic penalties for  
3       attempting to blend pipeline and quality gas up by  
4       utilizing PG&E's gas and moving it on to another  
5       pipeline (inaudible) making it more marketable.  
6       We, of course, had to pay for the -- pay the  
7       utility charges for that.

8               And as was brought up earlier by CIPA,  
9       the shut in of profitable wells due to PG&E's 50  
10      Mcf/d rule has cost the ability to produce some  
11      otherwise economic gas flow.

12             It's been our experience that we could  
13      increase our own production, primarily in the Rio  
14      Vista Gas Field, by up to 25,000 a day. In order  
15      to accomplish that, we would require -- we would  
16      have to acquire PG&E's gathering system. We have  
17      been in negotiations for two years with PG&E to  
18      make that acquisition. And for all the reasons  
19      that PG&E mentioned we were unable to conclude any  
20      type of sale.

21             Low Btu gas could also be made available  
22      to other additional end-users without regulatory  
23      burden. I've already mentioned these.

24             In conclusion, Calpine needs more gas  
25      transmission and storage capacity at reasonable

1 rates in order to provide reliable power and meet  
2 the needs of the core market.

3 That market needs to provide capacity at  
4 the best price and under the best available terms,  
5 whether that be a utility function or interstate  
6 pipelines.

7 There needs to be provided a level  
8 playing field in the State of California  
9 (inaudible) development of storage and pipelines,  
10 gas production for the state.

11 And the regulatory environment should be  
12 constructed to allow for alternatives and not  
13 mandate specific courses of action.

14 And as provided in the report,  
15 explaining, we think that the Energy Commission  
16 should provide a lot of the early warning by  
17 measures that are outlined in the report.

18 Thank you.

19 PRESIDING MEMBER MOORE: Thank you very  
20 much. We have a couple of questions for you. In  
21 terms of the new Sonoran Pipeline, I'm assuming  
22 that Calpine plans to take some percentage of firm  
23 out of that over (inaudible). Can you say what  
24 your expectations on firm are --

25 MR. BARND: Yeah, we are going to have,

1 of the 750,000 a day of phase I, we have a binding  
2 commitment with Sonoran for 400,000, over half.

3 On phase II, which is anywhere from 1  
4 Bcf up to 1.5 Bcf, depending on the market, we  
5 have indicated 500,000. So a half a Bcf a day.  
6 These will be under long-term, 20-year  
7 commitments.

8 PRESIDING MEMBER MOORE: For all the  
9 power plants that Calpine is planning up and down  
10 the I-5 corridor, will this pipe satisfy those  
11 needs? Or will you still be reaching out to the  
12 (inaudible)?

13 MR. BARND: Whatever the (inaudible) is  
14 going to bring, I would suspect there will be  
15 other generators along the I-5 corridor who would  
16 want (inaudible) this particular pipeline. I  
17 don't have information about which generators in  
18 California have expressed any interest in the  
19 Sonoran Pipeline.

20 And it could be very conceivable that  
21 the pipeline will serve other generators.

22 PRESIDING MEMBER MOORE: But if it  
23 didn't, it could satisfy virtually all of  
24 Calpine's needs?

25 MR. BARND: Potentially it could, but

1 Calpine is developing a diversified portfolio, so  
2 we would not want 100 percent of our gas needs to  
3 be met out of the southwest.

4 Again, we have a very large stake in  
5 Canada. We've acquired NCAL and a number of other  
6 Canadian producers. We have take substantial  
7 positions in British Columbia and on the west  
8 coast pipeline system, and on the (inaudible) up  
9 in Canada, as well as participation in the recent  
10 PG&E expansion, participated in the Kern River  
11 expansion; we participated in almost all the  
12 expansions in addition to the Sonoran. This is an  
13 indication of Calpine's real needs to find  
14 reliable sources of gas to make -- we're not  
15 taking it as a let's just buy from the market when  
16 we need it. Calpine is building power plants on a  
17 long-term basis and (inaudible).

18 PRESIDING MEMBER MOORE: Well, I sure  
19 appreciate your remarks today. I'm glad you came  
20 in.

21 MR. BARND: Thank you.

22 PRESIDING MEMBER MOORE: Thank you very  
23 much.

24 Phil Davies from Wild Goose.

25 MR. DAY: Mr. Chairman, Mike Day on

1       behalf of Wild Goose.  If I could ask for the  
2       lights to be turned on, I don't have slides, but I  
3       do have copies of our materials to pass out.

4                   (Pause.)

5                   MR. DAY:  Thank you.  Wild Goose Storage  
6       is a wholly owned subsidiary of Alberta Energy  
7       Corporation, and is the first independent storage  
8       provider in California.  And we are in operation,  
9       have been for nearly three years now.

10                  And as a result of an open season last  
11       winter the Wild Goose Storage facility is  
12       completely subscribed to its existing level of  
13       capacity for the next four to five years.

14                  In addition we announced open season for  
15       an expansion of the project which was mentioned in  
16       a couple of the earlier presentations.  And  
17       although I'm not able to release the exact results  
18       of the open season, we received extremely strong  
19       support for all of the expansion that we put out  
20       there.  So we're very pleased about that.

21                  In the materials we have before you  
22       there's -- some of this I'll go through quickly in  
23       the beginning because it dovetails with what other  
24       parties have said.

25                  And then I'd like to talk with more

1        specifics about the proposals that were made in  
2        the staff draft report. We think the Commission  
3        has done an excellent job of capturing the state  
4        of the gas infrastructure in California, and we  
5        just have some comments on how we might go forward  
6        in the future.

7                    But as you've seen from a number of the  
8        charts, particularly those I believe that PG&E  
9        just showed us this afternoon, the gas demand in  
10       California is highly volatile, very weather  
11       sensitive, and generation demand is the driver of  
12       that volatility.

13                   And although there's obviously a need  
14       for interstate pipeline capacity, because a lot of  
15       people are planning to build one, we think that  
16       it's a peak period problem as much as anything, in  
17       addition to what are we going to do to satisfy  
18       averaging demands, and in that situation  
19       particularly when even the existing pipelines are  
20       not completely utilized at all times of the year,  
21       storage can be a very efficient solution for  
22       solving your peak period reliability concerns.

23                   In addition, storage in the state on  
24       system, on the utility distribution system, is  
25       essentially more reliable. It requires less

1 building of pipe in order to get the gas to the  
2 customer. It can't be diverted by an upstream  
3 market as when Northwestern or Midwestern clients  
4 would buy gas away from the California border  
5 before it's delivered. And the regulation of  
6 storage facilities like Wild Goose are within  
7 California's jurisdiction.

8           There are a number of different benefits  
9 from using storage, and the ones that we've  
10 identified so far, both for our existing project  
11 and for an expansion, include improving the  
12 transmission load factors on the utility, moving  
13 gas at off peak periods so that we can inject gas,  
14 but overall increasing the load factor on the  
15 utility pipelines so that all customers see  
16 reduction in their transmission totals when those  
17 increased load factors are rolled into PUC rates.

18           In addition, storage customers can put  
19 their gas onto the market in periods of peak  
20 prices, selling into those peaks and dampening  
21 prices. And when we can generate maximum  
22 withdrawal into those markets, we can have a very  
23 significant impact of reducing prices. And those  
24 prices will flow through to all customers who are  
25 buying in that market.

1                   And we here include an example that a 30  
2                   cent dampening for just one month could save  
3                   PG&E's noncore market \$10 million.

4                   In addition, we can reduce curtailments  
5                   and diversions for the core if they are able to  
6                   take advantage of independent storage, as well.  
7                   And as we say, all these types of benefits can  
8                   benefit all types of customers, not just the  
9                   storage customers of Wild Goose or any other  
10                  independent.

11                  In addition, independent storage  
12                  provides some other efficiencies because we don't  
13                  add to the utility ratebase. We have been charged  
14                  by the Commission when we were certificated to  
15                  make our investment entirely at our own risk. We  
16                  have no captive customers, and we have no service  
17                  territory. We have to successfully compete to  
18                  sell our services or we don't make any money and  
19                  we don't recover our investment.

20                  The only exception is making sure that  
21                  the backlog transmission system is upgraded  
22                  sufficiently so it can take the gas that we can  
23                  deliver out of our gas warehouse, out of the  
24                  storage facility.

25                  And we also believe that there's

1       beneficial competition created by the introduction  
2       of independent storage producers to the market  
3       because the utilities will have to compete in  
4       order to sell their storage service to the noncore  
5       market and hopefully to the core. Because we  
6       think that independent storage can provide low  
7       cost and efficient storage for the core market, as  
8       well.

9               If you try to determine how much  
10       independent storage or how much storage in total  
11       the state needed, we would argue that you  
12       essentially have to look at this on a case-by-case  
13       basis. It is the right policy to make independent  
14       storage producers bear the risk of their own  
15       investments. We don't want a guaranteed return  
16       from anyone.

17              And at the same time, the modest cost  
18       for transmission upgrades to accept the gas that  
19       can come out of our systems is quickly paid for  
20       because it produces significant benefits for the  
21       whole system.

22              And so we think it's appropriate to have  
23       a slack factor for storage capacity as well as for  
24       transmission capacity.

25              But each individual project can be

1       evaluated on a case-by-case basis. Look at the  
2       benefits it can provide with its capacity.  
3       Measure that against the cost of interconnecting  
4       it with the system, and determining whether there  
5       are benefits for all types of customers.

6               Turning to the question of what should  
7       you do to encourage the development of storage,  
8       and we do strongly support and thank the staff for  
9       their recommendation in the report that  
10       independent storage should be encouraged. We  
11       obviously agree with that.

12              There's a number of things we would  
13       suggest that you look at. Number one, don't  
14       rebundle utility storage. In fact, we should go  
15       in the opposite direction, fully unbundle utility  
16       storage that is there.

17              We haven't quite completely got to the  
18       point of having fully unbundled storage on most  
19       systems. We should get to the point where the  
20       utilities are at risk for any uncommitted or  
21       uncontracted for storage. It should not be placed  
22       in the transmission rates of all customers. And  
23       it should be such that all customers have the  
24       opportunity to either purchase utility storage or  
25       not, as they choose, so that they have the options

1 of trying to find the right package of storage  
2 services to meet their particular needs.

3 Bundled storage includes too many cross-  
4 substances. Essentially what happens is customers  
5 who have expensive storage profile, they inject a  
6 lot of gas in and out. They're moving all the  
7 time on the system. They're swinging on the  
8 balancing flexibility built into the system that  
9 exists today. And there's very generous balancing  
10 allowances on both the California LDCs.

11 Those customers are getting storage  
12 cheaper than it actually would cost them if they  
13 had to go out and get it themselves. And  
14 customers who are relatively flat load and don't  
15 place many demands on the system are subsidizing  
16 those customers.

17 We think that the better thing to do is  
18 unbundle storage, let customers acquire the  
19 storage they need for their own particular uses,  
20 and those who require storage pay for what they  
21 need. And full on bundling sends the correct  
22 price signals to the utilities in terms of  
23 managing their own storage.

24 So we would ask you to consider, in fact  
25 we'd strongly recommend that you consider amending

1 the report to delete the recommendation about  
2 rebundling storage service for the utilities, and  
3 in fact, urge that storage be fully unbundled.

4 In addition, we know that some of the  
5 concern about this, because we've had  
6 communication and discussions with lots of people,  
7 including the PUC Staff and some of the consumer  
8 groups like TURN, that the concern about  
9 rebundling was generated out of concern about what  
10 the generators and noncore customers did last  
11 summer when it appeared that they did not fully  
12 utilize storage that was available to them. And  
13 then there was not as much gas in storage to be  
14 bid into the market when we had price spikes later  
15 on in the year.

16 We have analyzed the data from last  
17 summer, and what we have found is that at the time  
18 that customers would have been still injecting for  
19 winter storage, the normal storage injection  
20 cycle, they were faced with futures market prices  
21 which showed that the summer prices were much  
22 higher, or at least significantly higher than  
23 winter prices. A very unusual situation.

24 In that situation many noncore customers  
25 essentially optimized their resources by saying

1 I'll sell this gas now for a high price because I  
2 can buy it back less expensively in the winter.

3 Of course, what happened was the futures  
4 prices did not pan out. The prices were again  
5 higher in the winter, and they were not able to  
6 buy it back as cheaply.

7 But this has had a significant impact on  
8 the market. The customers are not repeating that  
9 mistake. You can see futures prices now which can  
10 show you approximately the same thing, that you  
11 can get a very high price for your gas this summer  
12 because we have a summer generation peak. And at  
13 the same time prices in the winter are, you know,  
14 around the same, or possibly a little lower.  
15 Customers might be tempted to do the same thing.  
16 But they are not doing it.

17 They are injecting their gas. We're on  
18 national five-year averages for injection in  
19 California and elsewhere in the west. It appears  
20 to us that the market is working, customers have  
21 decided that they should not go for the easy play  
22 and take profits now in the summer at the expense  
23 of not having enough injection to meet their needs  
24 later on.

25 We think that's a positive development

1       and we think that it indicates that you don't have  
2       to rebundle the storage system in order to assure  
3       that it will work the way it's supposed to. And I  
4       think that's very very important.

5               We're relying on these customers to sort  
6       of behave responsibly and to respond to the  
7       economic signals that they're given, and it  
8       appears that that's happening.

9               The other positive indicator in that  
10       regard is the results of Wild Goose's on open  
11       seasons, and the other pipeline open seasons.  
12       Generators are making significant investments in  
13       storage assets, by taking capacity in open seasons  
14       and by signing up for new pipeline capacity.

15              You just heard Calpine indicate they're  
16       looking to acquire storage, they're looking to  
17       acquire pipeline capacity, they're not alone in  
18       this, amongst the generation community.

19              So to us that says the generation  
20       community and noncore customers are investing in  
21       infrastructure which is exactly what you would  
22       want them to do in order to provide for their own  
23       needs.

24              The other thing that would encourage the  
25       development of independent storage along with the

1 list of them, that I think are things California  
2 can and should take care of.

3 Number one, you could reduce the time  
4 for approving independent storage projects. At  
5 the moment we have to go through two types of  
6 duplicative proceedings in order just to get the  
7 right to use eminent domain. And while we always  
8 want to work out acceptable relations with  
9 landowners before we construct a project in their  
10 area, we certainly did that on our base project,  
11 it's almost impossible to build a pipeline in  
12 California without having the ability to use  
13 eminent domain.

14 So, California could reduce the  
15 requirements for the unnecessary second eminent  
16 domain hearing.

17 In addition, expansions maybe should not  
18 be subject to an additional CPCM requirement,  
19 having to go through another hearing at the PUC to  
20 simply expand existing storage fields, to us,  
21 seems excessive.

22 Another thing that I think could  
23 possibly meet the test of what the staff was  
24 looking for in terms of ways to encourage people  
25 to use storage properly is to change the balancing

1 rules in California.

2 We think that the 5 and 10 percent slack  
3 balancing rules in California are extremely  
4 generous. What happens is customers use this  
5 flexibility and swing on the system, essentially  
6 being cross-subsidized, or imposing costs on the  
7 other customers.

8 And there's no disincentive to stress  
9 the system this way. Nor is there an incentive  
10 for a customer to go out and contract for storage.  
11 So we think that reducing the flexibility in the  
12 balancing rule, essentially having customers live  
13 up to a tighter standard, would suggest that they  
14 would then be encouraged to go out and contract  
15 for storage they need.

16 Normally whenever someone like Wild  
17 Goose would bring up something like this, we would  
18 be accused of trying to feather our own nest  
19 because we want people to buy our storage.

20 But we are fully contracted for the next  
21 five years. We've had a very successful open  
22 season. Changing these rules isn't necessarily  
23 going to benefit us. We're recommending it  
24 because we think it's the right thing to do to  
25 send the signals the Commission's report indicated

1       it wanted to send, which is if you need storage  
2       for reliability you ought to go out and get it.  
3       We would rather have the customers get price  
4       signals through proper balancing rule than a  
5       commanding control solution. And that's our  
6       recommendation.

7                   And lastly, we think it is important to  
8       indicate to the utilities that they should have  
9       both an incentive and the obligation to maintain  
10      their backbone of their systems adequately to  
11      accept the withdrawal capacity of independent  
12      storage facilities.

13                   We're very pleased to hear that both the  
14      utilities are considering backbone transmission  
15      upgrades. We think they frankly should always be  
16      able to take the deliverability from independent  
17      storage with an equal priority to the withdrawal  
18      they take from their own storage that's required  
19      by the PUC decisions in this area. Nor should  
20      there be any discriminatory tolls that impose  
21      higher costs on customers of independent storage  
22      than on utility storage.

23                   But the quid pro quo for that is that  
24      any expansions that, or upgrades of transmissions  
25      capacity the utility has to build in order to

1       accommodate those utilities should be assured  
2       recovery of these costs in rolled-in rates.

3               It's their job to maintain the backbone,  
4       so that whether it's intrastate capacity coming  
5       in, or storage withdrawals that are coming in,  
6       they can get to the burner tip. And when they do  
7       that, when they maintain that system they should  
8       be able to obtain cost recovery for it.

9               And that completes our recommendations  
10       on our formal report. I looked with some interest  
11       at those that Mr. Wood mentioned in his  
12       presentation. And of the ones he's got there I  
13       think the only one that I would want to comment on  
14       directly is encouraging secondary storage market  
15       development. That is definitely something that we  
16       think is important.

17               We want our customers to be able to  
18       trade their capacity on the secondary market. We  
19       supported for instance the comprehensive  
20       settlement in southern California which is still  
21       before the PUC because of unbundled intrastate  
22       transmission capacity and an unbundled storage  
23       capacity that allowed for a secondary market. We  
24       strongly believe that that's very important and  
25       very helpful to the market.

1                   If you go through that point and you put  
2                   in reasonable balancing standards, we would argue  
3                   that some of the other strict requirements on  
4                   customers are more of a toss-up as to whether or  
5                   not they're necessary to implement.

6                   But, I'd be happy to answer any  
7                   questions you have. And once again, we appreciate  
8                   the work of the staff and the Commission in  
9                   preparing the report, and thank you for the  
10                  opportunity to appear today.

11                 PRESIDING MEMBER MOORE: Thank you, I  
12                 appreciate your remarks very much. I'm going to  
13                 turn to Norm Pedersen.

14                 MR. PEDERSEN: Thank you, Commissioner.

15                 PRESIDING MEMBER MOORE: How old is the  
16                 Generation Coalition? I'm not sure I'm familiar  
17                 with it.

18                 (Pause.)

19                 MR. PEDERSEN: Thank you, Commissioner,  
20                 my name is Norman Pedersen, and I'm speaking here  
21                 on behalf of the California Generation Coalition.

22                 With me today, as well, are Karl Meyer  
23                 and Jim Rudolph from NCPA and Dave Arthur from the  
24                 City of Redding.

25                 The California Generation Coalition,

1       made up of generators, municipal and non-  
2       municipal, located both in northern California and  
3       in southern California. We participate actively  
4       in both PG&E and Southern California Gas Company  
5       matters in the CPUC.

6               PRESIDING MEMBER MOORE: How old is the  
7       Coalition?

8               MR. PEDERSEN: The Coalition has been  
9       around for quite some time, for years it was  
10      primarily the Southern California Utility Power  
11      Pool with respect to southern California matters.  
12      It was made up of the Los Angeles Department of  
13      Water and Power, the Cities of Burbank, Glendale,  
14      Pasadena, and the Imperial Irrigation District.

15              Membership has expanded. Today  
16      (inaudible) southern California we call ourselves  
17      naturally, The Southern California Generation  
18      Coalition. When we're acting in northern  
19      California, we call ourselves the Northern  
20      California Generation Coalition.

21              Today we're speaking to you on a  
22      statewide basis, and so we are The California  
23      Generation Coalition.

24              First, Commissioner, I'd like to say  
25      that we were pleased in seeing the staff report

1       which we're addressing today. We strongly support  
2       the direction the staff is taking. We don't know  
3       what your timetable is, but at the CPUC they do  
4       have currently ongoing an investigation into  
5       Southern California Gas (inaudible) issues.  
6       Testimony is due on June 15th.

7               I don't know whether you're going to be  
8       able to get the report polished up and ready to go  
9       in time for that day. If it would be possible for  
10      you to do so, and get it submitted in that  
11      proceeding, we believe it will be very helpful for  
12      the judge, for Judge Brown and Commissioner Bilas  
13      of the Commission, to have before them in San  
14      Francisco.

15             As you'll see from my remarks we  
16      strongly agree with the staff conclusions that we  
17      need to add capacity and we need to add enough  
18      capacity to have a slack factor.

19             There was a comprehensive settlement  
20      proposed at the Commission, the California Public  
21      Utilities Commission that some speakers have  
22      mentioned. There were two other settlements  
23      proposed.

24             One which actually would be adopted by  
25      the proposed decision, which is pending before

1       that Commission. It was called the interim  
2       settlement. Another one was called the post-  
3       interim settlement.

4               The California Public Utilities  
5       Commission proposed decision would reject the  
6       comprehensive settlement. We believe that's the  
7       right way to go. And it's the right way to go  
8       because we do have an intrastate bottleneck  
9       problem. That was pointed out in the proceeding  
10      at the CPUC by the exhibit that you see replicated  
11      here.

12             It shows that there's 3500 a day of  
13      take-away capacity on the SoCalGas system with  
14      incoming capacity substantially in excess of that.  
15      And, of course, what we've seen in the staff  
16      report are not this table, but other tables that  
17      deal with the issue (inaudible) on a statewide  
18      basis, as well as a utility basis.

19             We believe that it's a correct  
20      observation that the problem is a bottleneck on  
21      the intrastate pipeline at the point of take-away  
22      capacity.

23             Now you've seen this slide. This is  
24      from SoCalGas. This shows that this year we're  
25      going to be operating at just about 100 percent

1 load factor. We've seen the same thing from PG&E.

2 As far as where we're going, going  
3 forward, the problem is only going to get worse.  
4 We do see substantial intrastate pipeline capacity  
5 proposed in California. Not even taking into  
6 account the results of the El Paso open season,  
7 the results of which we do not yet know, we have  
8 the open season results we see on this slide with  
9 something like 4.5 Bcfd of new capacity proposed  
10 to be built to California.

11 As I mentioned, there's at least one  
12 very very large substantial pipeline addition that  
13 is not reflected here, and that's what might be  
14 done by El Paso.

15 Bottlenecks make the difference. This  
16 is shown by this slide on the basis spreads that  
17 we've seen developing between border prices into  
18 SoCalGas as compared to the San Juan Basin.

19 On the next slide we've seen something  
20 similar, but less dramatic on the PG&E system.  
21 You don't see -- you do see basis spread, but you  
22 don't see after the December experience, some of  
23 those peaks that we saw on the previous slide  
24 regarding SoCalGas, we agree with PG&E, that that  
25 is directly attributable to the fact that you had

1 more available capacity on the PG&E system than we  
2 have had on the SoCalGas system.

3 As far as relieving the basis spread is  
4 concerned, we believe that you do have to have --  
5 you have to allow for a slack factor. The PUC, as  
6 I think a couple of the speakers mentioned  
7 earlier, back in 1990, adopted the standard that  
8 there should be a 15 to 20 percent slack factor  
9 above cold year forecast.

10 Now we've heard today SoCalGas advocates  
11 an average year slack factor. PG&E has advocated  
12 dry hydro. In the proceeding in which testimony  
13 is going to be submitted on June 15th, we looking  
14 forward to making a recommendation, I'm not sure  
15 we're there, on what our recommendation will be.

16 The Commission is right; it's hard to  
17 identify just exactly what the standard should be,  
18 but we're saying the things that it should be  
19 coming to take into account both cold year and dry  
20 hydro conditions.

21 Furthermore, the forecast built upon  
22 should be one that adequately reflects electricity  
23 transmission constraint and adequately affect  
24 local transmission requirements such as large  
25 support of load following.

1                   As far as cost recovery is concerned, we  
2           do agree that as long as you're building capacity  
3           to provide for requisite slack factor, all  
4           customers benefit. The point is very well taken  
5           that in just one day that those very substantial  
6           spikes we saw on the slide regarding SoCalGas,  
7           just one day of very substantial commodity spikes,  
8           you can cover the cost of capacity such as what  
9           SoCalGas is talking about installing.

10                   And this is what they're talking about  
11           installing right now. I believe SoCalGas  
12           presented its slide. They showed four projects  
13           that they had in the works. We applaud SoCalGas,  
14           and we encourage SoCalGas. We don't think that  
15           this will be sufficient.

16                   There are additional projects that we do  
17           think should be looked at. One is additional  
18           capacity, do we bring gas into the SoCalGas system  
19           from Mojave, from Kern River, build Sonoran for  
20           the pipelines that go into Kern County.

21                   There's a complex of interconnection  
22           points involving Wheeler Ridge, Adelanto, and  
23           Hector Road. We believe there should be  
24           additional capacity, we can look at additional  
25           capacity from those delivery points into the

1       SoCalGas system.

2               By the way, in the interim settlement,  
3       which would be approved if the Commission adopts a  
4       pending proposed decision in the gas industry  
5       restructuring proceedings at the CPUC, the  
6       standard would be established. It would trigger  
7       some expansion of Wheeler Ridge.

8               We think also that attention should be  
9       given to the possibility of expansion at Topock.  
10       We do understand that that would be more expensive  
11       expansion, but it's something that should be at  
12       least investigated, we believe.

13              There are currently negative incentives  
14       at the PUC which preclude or forestall prompt  
15       expansion of capacity.

16              One is the PBR mechanism that SoCalGas  
17       has. SoCalGas will be making a filing for a new  
18       PBR mechanism; they'll be making that filing on  
19       December 21st. The PBR mechanism that we have in  
20       place right now delays rate base recovery.

21              Back when SoCalGas' current PBR  
22       mechanism was being proposed, we were involved in  
23       that proceeding, and we advocated a mechanism that  
24       was different from the one that SoCalGas has now.  
25       It's one that would not provide a disincentive to

1 prompt capacity additions.

2 We proposed that because LADWP, Burbank,  
3 Glendale, Pasadena, IID were all there for the  
4 curtailment experiences of 1980 that we didn't  
5 want to see replicated.

6 The Commission decided to go a different  
7 direction. We believe that in the PBR proceeding  
8 coming up there's a possibility that some of these  
9 issues can be addressed.

10 Another negative incentive that we see  
11 that may forestall interest in a gas utility to  
12 expand capacity in a timely fashion is SoCalGas  
13 gas cost incentive mechanism. That mechanism  
14 provides an incentive to SoCalGas to sell gas and  
15 sell hub services to noncore customers. It shares  
16 the profit 50/50 with core ratepayers.

17 Earlier this year, right at the turn of  
18 the year, January, the Energy Division came out  
19 with a report on the SoCalGas gas cost incentive  
20 mechanism. SoCalGas has regularly been getting  
21 annual award under the mechanism. The year seven  
22 award, which is going to be announced on June  
23 15th, we expect to be very large.

24 The staff report indicated that at least  
25 the earlier awards were primarily attributable to

1 not SoCalGas doing a particularly effective job  
2 buying gas for the core, but rather when it was  
3 making, selling gas to noncore customers and  
4 providing hub services to the noncore customers.

5 Our concern, Commissioner, is that  
6 SoCalGas' ability to get a benefit from the  
7 provision of gas sales to noncore customers, from  
8 the provision of hub services to noncore customers  
9 may give them something of a different incentive  
10 than to install the capacity that would obviate  
11 the need for the gas sales and the hub services.

12 Another factor, SoCalGas's risk sharing  
13 mechanism. SoCalGas is at risk for through-put.  
14 That may be a contributing factor. That can be  
15 addressed in the BCAP that will be filed with the  
16 CPUC coming up on September 17th.

17 Now what about on the PG&E Gas Accord.  
18 WE believe that some of the same factors are  
19 there. There is a delay in rate recovery, yet  
20 there is (inaudible) expansion of the PG&E system.  
21 We are concerned about the unbundled structure  
22 that PG&E has now. We are not supportive of it,  
23 as some of the speakers have been.

24 We believe that there is a possibility  
25 that if you have (inaudible) proceeding with the

1 open (inaudible) that has been discussed today,  
2 that you're going to create, that we would have  
3 created a constituency for capacity constraint  
4 because they would be interested in seeing the  
5 value of the capacity they hold and increase.

6 Also, of course, PG&E is 100 percent at  
7 risk for noncore revenues. And the extent to  
8 which PG&E is at risk that may be a disincentive.

9 Now, as far as the unbundling is  
10 concerned, we (inaudible) that customers benefit  
11 from an unbundled backbone system on PG&E. We  
12 don't see it that way. So, (inaudible) comes into  
13 PG&E from Malin, and this chart shows you the  
14 basis spread between Malin and PG&E Citygate. The  
15 customers who bear the burden of this basis spread  
16 are the on-system customers who don't control the  
17 capacity. The benefits of the basis spread go to  
18 those who do control the capacity.

19 I'd like to speak about storage for just  
20 a moment. First of all, the point is well taken  
21 that other speakers have made, the spring 2000  
22 experience of storage not being filled cannot be  
23 replicated in 2001. They also say generals fight  
24 the last war. Well, all this talk about problems  
25 of storage is really the same problem of the

1 building of the Maginot Line, fighting World War I  
2 rather than fighting World War II.

3 We don't have the same situation today.  
4 Nationwide we see AGA targets for storage  
5 injection being met, exceeded, as a matter of  
6 fact. We're seeing fairly consistently --

7 (End tape 2B.)

8 MR. PEDERSEN: -- account for about a  
9 third. So both the core and the noncore are  
10 filling storage.

11 Something else that is going to make a  
12 big difference as far as SoCalGas is what they're  
13 going to be doing with their Montebello, La Goleta  
14 and Aliso Canyon fields with the sale of cushion  
15 gas out of those fields. Overall we should have  
16 26 Bcf a day coming from Montebello, 14 from La  
17 Goleta/Aliso Canyon. Not all of that will be  
18 available this winter, but a substantial amount;  
19 probably 24 Bcf would be available.

20 We join those who say that no further  
21 incentives are necessary and we should not go back  
22 to rebundling.

23 On the other hand, it is important to  
24 note that there are some costs still bundled for  
25 both SoCalGas and PG&E. The storage that is used

1 by SoCalGas and PG&E to provide a (inaudible). We  
2 do not join Calpine with urging unbundling of  
3 that. We do have some things that work. It seems  
4 the (inaudible) work. We're not advocating a  
5 change. And we are not advocating further  
6 unbundling. We don't want rebundling, but we're  
7 not advocate further unbundling.

8 So in conclusion, Commissioner, we  
9 strongly, as I mentioned at the outset, support  
10 the staff on the idea that we ought to have a 15  
11 to 20 percent slack factor. We think that the PUC  
12 was completely correct that in 1990 when we did  
13 allow that, by the way it was substantially at the  
14 urging of the CEC back a decade ago that the PUC  
15 get around to recognize that we did need to have,  
16 not only had it, but to have the slack factor.

17 We believe that we need to build on the  
18 slack factor. On the correct forecast  
19 assumptions, we believe that those are a  
20 combination of dry hydro/cold year and that the  
21 forecast should also take into account electric  
22 transmission constraints.

23 And we believe that there should be a  
24 review of what currently are regulatory  
25 disincentives for the California utilities to

1       adequately (inaudible).

2                   And I very much appreciate the  
3       opportunity to be here today. Thank you very  
4       much.

5                   PRESIDING MEMBER MOORE: Thank you, and  
6       I'm glad you came. Appreciate that very much.

7                   Now, I may have slipped up before in  
8       trying to get Eric Eisenman ahead of the -- so,  
9       please excuse me for my (inaudible). Welcome.

10                  MR. EISENMAN: Thank you. My name's  
11       Eric Eisenman; I represent PG&E National Energy  
12       Group, PG&E Gas Transmission Northwest, and the  
13       North Baja Pipeline Projects.

14                  I want to make a few comments on some  
15       statements that are in the report. First, I'd  
16       like to start with some comments on North Baja.  
17       I'm going to actually give a couple graphics if  
18       the light in the graphics works.

19                  On page 73, I believe, it says there are  
20       no firm capacity contracts on El Paso to serve the  
21       increased demand. There will be no flow on the  
22       North Baja Pipeline.

23                  Well, I can assure you there will be  
24       plenty of flow on the North Baja Pipeline next  
25       year, in fact. It will be pretty full running

1 from day one. And it's conceivable, maybe even  
2 likely, that we will be looking at expansion of  
3 the North Baja system within a year or two after  
4 its initial service date.

5 Most of the North Baja shippers are  
6 generators and they make huge investments in  
7 generation. And they will have long-term gas  
8 supply transportation arrangements in place.

9 What the report directly points out that  
10 the North Baja shippers may get firm capacity as  
11 part of El Paso's ongoing open season clauses to  
12 expand its pipeline. We need to watch that very  
13 carefully.

14 North Baja shippers may also require  
15 capacity from existing El Paso capacity holders,  
16 or they may buy gas at Ehrenberg. PG&E National  
17 Energy Group holds El Paso capacity right now that  
18 will likely eventually be used to serve, in part,  
19 the Otay Mesa plant that you recently licensed in  
20 the San Diego area.

21 I would also note on page 72 there was a  
22 brief description of a bi-directional lateral  
23 project from Daggett to Ehrenberg. And then  
24 another potential source for gas supply for the  
25 North Baja Project.

1                   That project, that comes -- you  
2                   potentially see gas coming off Kern River into  
3                   that project, and then into North Baja. But I  
4                   want to give you assurance that North Baja is  
5                   quite real and there will be some flow on it, a  
6                   lot of flow on it from day one.

7                   Continuing on North Baja, the next page,  
8                   on page 74, there is a statement that the CEC  
9                   should investigate whether the North Baja Project  
10                  would force curtailments under conditions as  
11                  experienced in the summer of 2000, and other  
12                  plausible scenarios.

13                  I guess I'd like to put a little  
14                  different spin on that. We think you're looking  
15                  at the Southern El Paso Line. It currently has a  
16                  capacity of about 1200. They are looking at an  
17                  expansion of that. There's a lot of potential new  
18                  demand on that line in Arizona.

19                  We're looking at potentially up to 8000  
20                  megawatts of developed into Arizona that's either  
21                  in advanced development or under construction,  
22                  that would be served by this same line. Now,  
23                  that's a lot of gas, and it could be over a Bcf  
24                  every day.

25                  Now, I would have some expectation that

1       there will be an El Paso expansion that will serve  
2       a lot of this, but I think the most likely  
3       scenario is any El Paso expansion will not, one-  
4       for-one, meet the increased demands from North  
5       Baja, the increased demands from the generation in  
6       Arizona.

7                   And as Mr. Barnds discussed, there's  
8       also the Sonoran Pipeline that could take some of  
9       these supplies into other markets, or to the  
10      Calpine projects around the state.

11                   This is the market responding. There's  
12      nothing wrong with all this. And the California  
13      market, specifically the southern California  
14      market, will respond accordingly. The market  
15      participants have to be given the opportunity to  
16      respond.

17                   Mr. Lorenz discussed the Kramer Junction  
18      Project. That's an example. I think even if you  
19      see demand in southern California lags, as has  
20      been forecasted, it's plausible, and maybe it was  
21      (inaudible) little bit. Over the next few years  
22      we will see greater supplies in southern  
23      California come to, over and beyond Kramer  
24      Junction, that is coming from (inaudible) and from  
25      Canada via PG&E.

1                   Right now it's hard to know. We have to  
2                   watch what happens with these El Paso expansions  
3                   and where this gas ends up going.

4                   SoCalGas, the list of projects, those  
5                   are all proven and should move forward. SoCalGas  
6                   and all the participants should continue to watch  
7                   what happens in that market. There may be  
8                   adequate room for structuring out on kind of a  
9                   macro basis, but that doesn't mean that there'll  
10                  be supplies there.

11                  However, the market needs to react, and  
12                  it shouldn't be regulated; it shouldn't be forced  
13                  upon SoCalGas or any of the market participants.  
14                  Let the market determine this over the next few  
15                  years, -- sort out these gas issues.

16                  Moving north several hundred miles to  
17                  gas transmission northwest system. On page 66  
18                  there's a discussion about upstream issues on gas  
19                  transmission northwest. And it's true that these  
20                  upstream markets in the Pacific Northwest use a  
21                  lot of capacity that was originally capacity for  
22                  wheeling into the PG&E system.

23                  This migration of the use of the  
24                  capacity to the north really started happening  
25                  several years ago when not only capacity to

1 California was being utilized, and there was just  
2 a higher value and a higher use for it in the  
3 northwest, and also in the Reno area. And, again,  
4 this is the market speed.

5 There has been a mismatch at Malin for  
6 several years. The 2002 expansion that is before  
7 FERC right now, and 2003 expansion, and we are  
8 proposing (inaudible) going on, that a lot of that  
9 will be the mismatch. But, again, it's best to  
10 let the market make the determination.

11 Also on page 66 there's a comment about  
12 the Alliance Pipeline and that it recently went  
13 into service, and is carrying a lot of gas from  
14 western Canada into the midwest. And there's some  
15 questions there in the report about western  
16 Canadian gas still being reliable supply source  
17 for California.

18 Well, believe it or not, since Alliance  
19 went into service power deliveries into California  
20 have increased, they haven't decreased. So what  
21 we're really seeing happening is Alliance, the  
22 TransCanada pipeline, which is the incumbent line  
23 out of -- they're the ones who are competing  
24 against. It's TransCanada that is really taking  
25 the hit.

1                   We have a lot of capacity holders with  
2                   long-term firm contracts with supply arrangements  
3                   for the long term, and the western U.S. apparently  
4                   is a higher value market than some of these  
5                   markets served by Canadian gas. So I want to  
6                   assure you that the Canadian gas will continue to  
7                   be a reliable source.

8                   But looking at what's going on at the  
9                   production level, drilling level, just a couple  
10                  pieces of data. Active rigs in western Canada are  
11                  much higher than a year ago. In fact, in April  
12                  they were 56 percent higher than in April of 2000.

13                  And gas completions, gas well  
14                  completions, the first four months in 2001 were 29  
15                  percent higher than the first four months of last  
16                  year. So, there have been high prices, and the  
17                  producing community in western Canada has  
18                  responded.

19                  There's been a lot of discussion in the  
20                  trade press about all the pipelines going up into  
21                  the arctic and the Northwest Territories. We're  
22                  looking at the real long term, towards the end of  
23                  this decade. That's going to be there, too. And  
24                  we believe that some of those supplies will come  
25                  down into California.

1                   So, please, when you're thinking about  
2                   the long term, keep that in mind, as well.

3                   And, while I think it's relevant to look  
4                   at other markets that are competing for Canadian  
5                   gas, it's also relevant to look at other markets  
6                   competing in other supply bases, San Juan -- there  
7                   are proposals to build new pipe capacity east out  
8                   of the Rockies. There's certainly been a lot more  
9                   San Juan gas going east than anybody ever would  
10                  have thought. And I've already mentioned the  
11                  demands in Arizona.

12                  Changing subjects a little bit, there's  
13                  been some discussion today and in the report about  
14                  slack capacity. And on page 26 we note the  
15                  heading about need for slack capacity on  
16                  interstate pipeline systems. And there has been a  
17                  whole lot of discussion about that today.

18                  It's good in concept, but somewhat  
19                  inconsistent with unbundled firm capacity rights  
20                  on an interstate pipeline. In fact, at Malin,  
21                  there's not slack capacity upstream, but rather  
22                  there's a shortage of capacity that I've already  
23                  discussed, these upstream needs.

24                  Interstate pipeline capacity is only  
25                  going to be constructed to California or anywhere

1       else when it's been contracted for. You're not  
2       going to see merchant pipelines building big  
3       amounts of capacity just to have a slack capacity.  
4       I don't envision that happening.

5               So, when you, the CPUC and other market  
6       participants think about slack capacity, you need  
7       to consider the dynamics of the interstate  
8       pipelines further.

9               I want to give you some assurance that  
10       as new generation is developed, licensed and  
11       constructed, not only here in California, but in  
12       the other states, the pipelines that serve, that  
13       we will continually look at pipeline expansions.

14              We've had some discussions with some  
15       generators who are developing projects that they  
16       anticipate being on line in 2004, and they say to  
17       us, well, we don't want capacity in 2003, we want  
18       it in 2004. They don't want to pay for it until  
19       then.

20              Well, we're open to that, so we've  
21       already got out on the street, a 2002 expansion,  
22       2003 expansion, and it's realistic that there will  
23       also be some kind of modest 2004 expansion to meet  
24       the needs generally of generators who are going to  
25       be online in that kind of timeframe.

1                   That concludes my comments, thank you.

2                   PRESIDING MEMBER MOORE: Thank you, I  
3           appreciate the comments. Can we -- are those in  
4           writing?

5                   MR. EISENMAN: No, I don't. You want  
6           them in writing?

7                   PRESIDING MEMBER MOORE: Well, no,  
8           (inaudible) perhaps you can translate and offer  
9           those to us.

10                  MR. EISENMAN: Okay, I'll --

11                  PRESIDING MEMBER MOORE: I'd love to  
12           have them.

13                  MR. EISENMAN: -- I'll do that.

14                  PRESIDING MEMBER MOORE: Thank you very  
15           much. Now, there may be others who would like to  
16           address us, but didn't submit a blue card. And  
17           I'd be happy to entertain that at this point.  
18           Come on up. Welcome.

19                  MR. KERNER: With your permission?

20                  PRESIDING MEMBER MOORE: Introduce  
21           yourself for the record, and I'm sure that the  
22           secretariat can write a card, as well.

23                  MR. KERNER: Absolutely. Douglas Kerner  
24           for Duke Energy North America and Duke Energy  
25           Trading and Marketing. Good afternoon,

1 Commissioner Moore, Ms. Jones. Thank you for  
2 being here. I will be very brief.

3 We do have written comments, which I  
4 will not expand upon or paraphrase for you. As  
5 I've been sitting here, however, listening I  
6 wanted to highlight one recommendation of ours.  
7 And I'm going to highlight it only because it's  
8 our recommendation and we think it has merit. But  
9 based upon the comments received, I think it's a  
10 matter on which you can actually be able to act  
11 decisively and quickly, that will have some pretty  
12 obvious, I think, benefits.

13 And that issue on planning reliability  
14 matter, is to move, and I would suggest moving on  
15 a statewide basis, to dry year assumptions with  
16 respect to the planning and consideration of  
17 interstate and intrastate capacity.

18 I think the testimony and presentation  
19 from PG&E in particular was extremely interesting.  
20 I think the material in front of you is pretty  
21 compelling that, as among different issues that  
22 have been discussed here, that the most highly  
23 sensitive factor in gas reliability is with  
24 respect to the event of an adverse condition, of  
25 somewhat, let's say, comparatively low

1 probability, has very severe effects on how  
2 severely stressed that slack capacity gets.

3 In consideration of the, what I also  
4 think was clear, tremendous cost effectiveness on  
5 which there seemed to be a consensus of opinion,  
6 on capacity expansion and because going to dry  
7 year also addresses the rather thorny issue of  
8 demand forecast uncertainty, and because it's  
9 likely to get you to a magnitude or amount of  
10 slack capacity which actually promises to position  
11 the commodity markets to compete one against the  
12 other.

13 I think there's tremendous merit, based  
14 on what you've heard so far, with the  
15 recommendation to go to that reliability criteria.

16 And, again, it's strongly recommended,  
17 the other interesting thing about the testimony on  
18 reliability criteria, which not many of them there  
19 are, no uncertainty seemed to be about what they  
20 should be.

21 But I think the case for moving to dry  
22 year is pretty compelling. I would think it's an  
23 action which you might be able to move to very  
24 quickly.

25 PRESIDING MEMBER MOORE: Thank you very

1 much.

2 MR. KERNER: Thank you.

3 PRESIDING MEMBER MOORE: We appreciate  
4 your comments. I'll look forward to seeing your  
5 written comments.

6 MR. KERNER: Yes, sir. We'll respond to  
7 the report. (inaudible) to reply to the report --

8 PRESIDING MEMBER MOORE: Yes,  
9 (inaudible) reply to the report and respond to it.

10 MR. KERNER: Thank you, again.

11 PRESIDING MEMBER MOORE: Anyone else who  
12 would like to address us who's here who didn't  
13 notify us ahead of time?

14 What I'd like to do is then encourage  
15 people to respond to the report. We would like to  
16 make the PUC filing if we can do it. (inaudible)  
17 our able staff with -- I'm not sure that they  
18 would trust me to go over and deliver the  
19 testimony, but perhaps one day I'll earn the right  
20 to do that.

21 (Laughter.)

22 PRESIDING MEMBER MOORE: What I'd like  
23 to ask is what is a time people think that they  
24 can meet. If I ask for closure on this by Monday  
25 of next week to get comments in, can people comply

1       with that? Is there anyone who couldn't make  
2       that?

3               All right, let's say close of business,  
4       then, on Monday of next week. And we'll entertain  
5       your comments, take them very very seriously. And  
6       I simply want to say while I suspect that there  
7       may be another of these hearings later in the  
8       year, perhaps on other issues, focused in  
9       different directions when we have more data and  
10      (inaudible) understand what the (inaudible).

11              But I want to personally thank every one  
12      of you for making the effort. I know what an  
13      effort it is to get your presentations together  
14      and come here and make these talks. Especially  
15      those of you who are returning to the FERC, one,  
16      two or more times. I'm well aware of those trips  
17      and how much time you spend on the road.

18              And I just want to say on behalf of the  
19      Commission and my own staff, I'm very very  
20      grateful for your testimony. It's enlightening  
21      for me, and I hope that we do a credit to you and  
22      what you have given us in the revised final  
23      version of our report.

24              We'll publish it on the web as well as  
25      trying to get a copy to each one of you.

1                   Thank you very much. I appreciate your  
2           coming.

3                   (Whereupon, at 2:55 p.m., the hearing  
4           was concluded.)

5                               --o0o--

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

## CERTIFICATE OF TRANSCRIBER

I certify that the foregoing is a  
correct transcript from the electronic sound  
recording of the proceedings in the above-entitled  
matter, to the best of my ability.

PETERS SHORTHAND REPORTING CORPORATION (916) 362-2345